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Office of Enforcement and Compliance Assurance
Office of Criminal Enforcement, Forensics and Training

National Enforcement Investigations Center

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Trip Report

Fort Berthold Advanced Monitoring 2018
Fort Berthold Indian Reservation, North Dakota
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NEIC

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* NEIC and EPA Region 8 personnel reviewed the data correlation table, but due to the large number of sites visited, unintentional errors may exist. The data correlation table is being constantly updated; the most current version is included with this report.

This Contents page shows all of the sections contained in this report and provides a clear indication of the end of this report.

INTRODUCTION

The U.S. Environmental Protection Agency's National Enforcement Investigations Center (NEIC) Geospatial Measurement of Air Pollution (GMAP) has the capacity to screen facilities for possible targeting of future inspections using EPA draft Other Test Method (OTM) OTM-33 (https://www3.epa.gov/ttn/emc/prelim/otm33.pdf) and draft OTM-33a (https://www3.epa.gov/ttn/emc/prelim/otm33a.pdf). GMAP consists of a mobile vehicle equipped with: an integrated cavity output spectrometer (ICOS) for methane (CH_4) and carbon dioxide (CO_2) measurements; a differential ultraviolet absorption spectrometer (DUVAS) for benzene (BEN), toluene (TOL), ethylbenzene (ETB), m-xylene (XYM), o-xylene (XYO), and p-xylene (XYP) (collectively referred to as BTEX) as well as sulfur dioxide (SO_2) measurements; a photo ionization detector (PID) for total volatile organic compound (VOC) measurements; a global positioning system (GPS); a compact weather station that provides motion-corrected wind speed and direction; and a mechanism for collecting air canister samples.

Data collected while GMAP is in motion can be plotted on Google Earth Pro (GEP) maps to help locate emission sources. Data collected while GMAP is stationary can be used to create weighted mean polar frequency plots (https://www.rdocumentation.org/packages/openair/versions/2.1-0/topics/polarFreq), where wind direction is the direction from the pole, wind speed is distance from the pole, and color represents concentration data. These polar plots can help locate emission sources. Under certain conditions, data collected while GMAP is stationary can be used to estimate the mass emission rate of a source using draft OTM-33a.

A FLIR model GF320 infrared (IR) imaging camera was used to attempt to locate sources of emissions found using GMAP. The FLIR camera has a bandpass filter on the detector to limit the image to a narrow band of the infrared spectrum where many hydrocarbons have spectral signatures; this allows the FLIR camera to image gas-phase hydrocarbon emissions. The FLIR camera can also use a high sensitivity mode, in which image subtraction is performed to highlight the movement characteristic of gaseous emissions.

All field sampling, field measurements/monitoring, and laboratory measurements described in this report are within the scope of NEIC's ISO/IEC 17025 accreditation issued by the ANSI-ASQ National Accreditation Board (certificate No. AT-1646), except for GMAP IR (ICOS)/UV (DUVAS) and motion-corrected anemometer measurements. NEIC is in the process of validating GMAP IR/UV measurement activities.

SUMMARY OF ACTIVITIES AND RESULTS

NEIC performed draft OTM-33 air monitoring using GMAP on the Fort Berthold Indian Reservation (FBIR) June 18-20, 2018. GMAP was escorted on the FBIR by tribal representatives. NEIC conducted a total of 39 GMAP mapping runs to measure for VOCs, methane, BTEX, and SO2. The routes traversed for all mapping runs are depicted in **Figure 1**.

The green lines shown on this mapping overview are intended only to show the monitoring locations. NEIC took 66 FLIR videos on the FBIR.

NEIC project manager Bill Squier collected four air canister samples June 18-20, 2018, that were subsequently analyzed at the NEIC laboratory in Denver, Colorado.

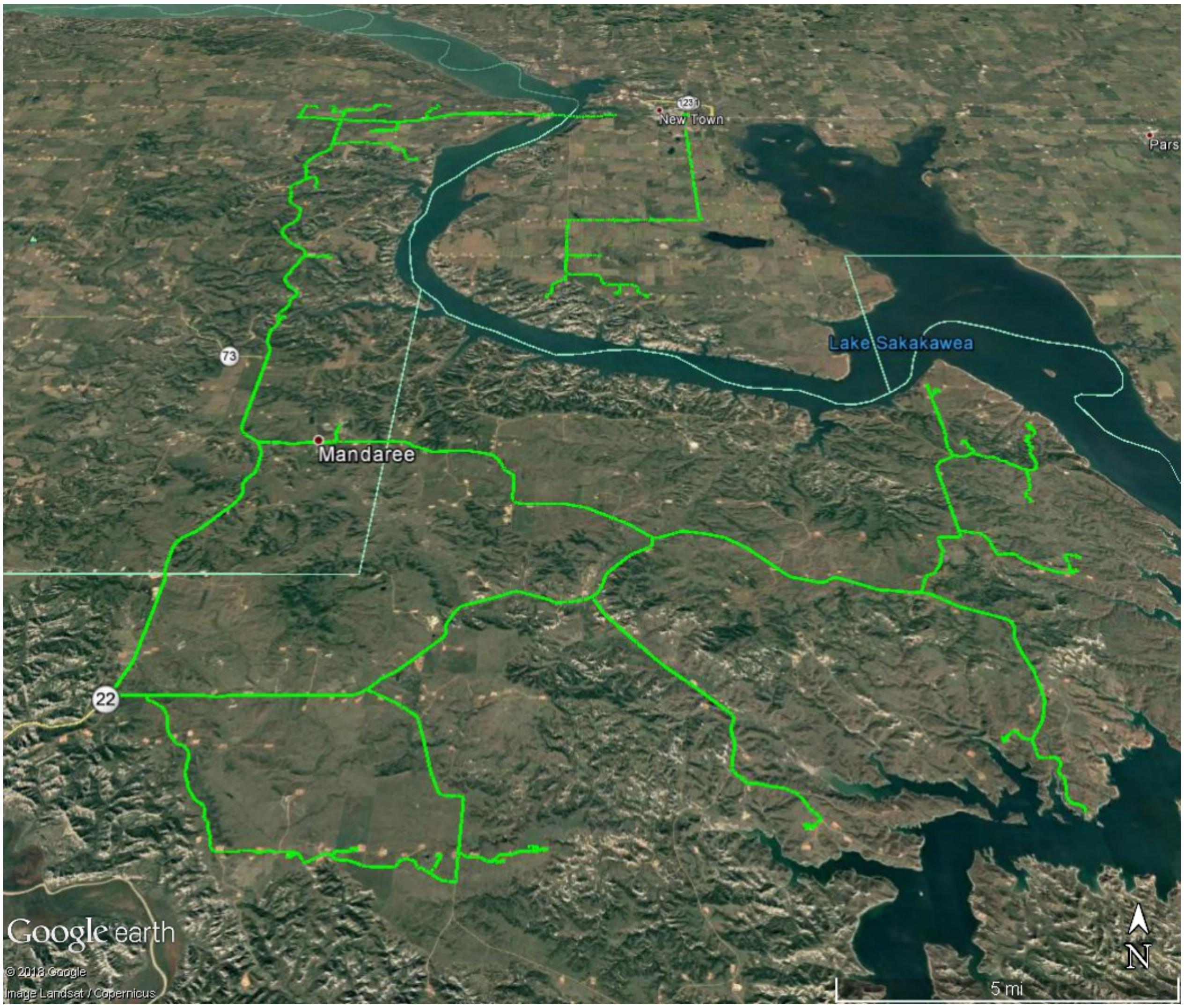

Figure 1. Fort Berthold GMAP routes
Fort Berthold Advanced Monitoring 2018
Fort Berthold Indian Reservation, North Dakota

FIELD ACTIVITIES

GMAP

To easily evaluate significant quantities of data generated by GMAP, analyte concentration values are displayed on GEP map plots for mapping files or on polar plots for stationary files. Concentration readings for each analyte are generated approximately every second, and these data are recorded, along with the corresponding GPS and meteorological data.

For each mapping file containing an elevated analyte concentration, the concentration data are converted into color bar graphs, which are overlaid on the map plots. For each individual mapping run, the highest analyte concentrations are displayed in red and the lowest concentrations are displayed in green on the color bar graphs. Concentration values lower than the mapping scale minimum (green) value used appear as green lines. Concentrations higher than the mapping scale maximum (red) value used appear as proportionally taller red bars. Each bar corresponds to a 2.5-meter distance travelled by GMAP; the concentration value shown on the bar is the highest concentration value recorded inside that distance. Where available, wind arrows are provided for each concentration bar. The direction of the arrow is the wind direction, and the length of the arrow is proportional to the wind speed. Due to instrument limitations, wind data are not available when the vehicle exceeds 25 miles per hour (mph).

Overview of GMAP Mapping Surveys

As mentioned earlier, concentration readings for each analyte (CH_4, BTEX, VOCs, and SO_2) are generated approximately every second. The three GMAP instruments, ICOS, DUVAS, and PID, are treated differently for GEP mapping purposes due to differences in the way data must be processed to generate representative maps of the data.

The ICOS CH_4 concentrations are reported in parts per million volume (ppm) and show an atmospheric background concentration of approximately 1.9 ppm. The signal from CH_4 emission sources comprise readings above background. There are many sources of CH_4 emissions, not all of which are areas for concern. To avoid generating maps that do not warrant further investigation, mapping scales for CH_4 are fixed at 2 ppm minimum (green) and 4 ppm maximum (red), unless otherwise noted. All CH_4 maps are created, regardless of their maximum value, so that areas surveyed without significant emissions can be seen on the maps.

The ICOS CO_2 concentrations are reported in ppm and show a geographically variable atmospheric background concentration of approximately 400 ppm. CO_2 concentrations are only reported as necessary to provide source characterization data using mapping scales that are chosen for source characterization purposes for each map generated. CO_2 maps may be necessary to distinguish VOC readings between stationary non-combustion sources (which have no CO_2 emissions) and interfering mobile combustion sources (which have CO_2 emissions). A map of all CO_2 data collected is included as a separate Google Earth keyhole markup language (kml) file in this report because it may be useful in interpreting other data collected inside JCL.

DUVAS BTEX concentrations are reported in parts per billion volume (ppb). Because of the manner in which the DUVAS instrument generates concentration data, DUVAS analyte concentrations require special processing. Mapping scales are adjusted to make the map appearance correct; reported values are not corrected for zero offsets. 40 Code of Federal Regulations (CFR) Part 136 Appendix B, "Definition and Procedure for the Determination of the Method Detection Limit," is used to determine the 95 percent upper confidence limit (UCL) of the method detection limit (MDL) for all GMAP BTEX concentration values. Positive zero offset values calculated by averaging instrument zero checks performed at the beginning and end of each sampling day are added to the UCL to determine each day's adjusted UCL for each BTEX analyte. BTEX zero offset adjustments are necessary due to limitations of the DUVAS instrument. Each BTEX analyte's daily adjusted UCL, UCL, and MDL are presented in **Table 1**. The scale used for each BTEX analyte in the GEP maps is fixed for each sampling day at a minimum (green) equal to the MDL, plus positive daily zero offsets to a maximum (red) equal to two times the UCL plus positive daily zero offsets. Values greater than two times the adjusted UCL, plus positive daily zero offsets, appear as proportionally taller red bars. **Table 2** lists all BTEX values above the daily adjusted UCL.

Table 1. DAILY GMAP ADJUSTED UCL
Fort Berthold Advanced Monitoring 2018
Fort Berthold Indian Reservation, North Dakota

	Benzene (ppb)	Toluene (ppb)	Ethylbenzene (ppb)	o-Xylene (ppb)	m-Xylene (ppb)	p-Xylene (ppb)	SO_2 (ppb)
6/18/2018	17	36	35	127	57	21	79
6/19/2018	17	34	35	110	57	20	104
6/20/2018	17	34	35	116	57	22	110
UCL	14	34	35	88	57	14	72
MDL	6	15	16	40	26	6	33

The PID is calibrated with isobutylene, and all reported values for VOCs are in ppb as isobutylene. Due to wide natural variances in background concentration and to the many sources of VOCs, not all of which are areas for concern, VOCs are not mapped unless there is a difference between the highest and lowest VOC value in a file of at least 200 ppb, unless otherwise noted. VOC map scales are set to the file minimum value, plus 100 for the map scale minimum (green) and the file minimum value, plus 300 for the map scale maximum (red), unless otherwise noted.

As discussed earlier, the concentration values derived from the GMAP mapping files are presented in the GEP maps. These maps are saved as kml files. For each day that GMAP mapping files were collected, a separate kml was created containing all CH4 concentrations and the BTEX concentrations noted in the "Elevated GMAP Readings" (**Table 2**). All VOC mapping files with a concentration noted in the "Elevated GMAP Readings" (**Table 2**) have a unique kml.

Reading GMAP Results

GEP is a free software program that may be downloaded and installed from the Internet. Controls in the upper right of the GEP image allow the user to turn the view and to set the magnification so that the image can be seen from the best perspective. After the software is installed, double-clicking a kml file will open the file in GEP under “Temporary Places” in the “Places” box on the left side of the screen. **Figure 2** is a screenshot of a GEP image showing selected data from the kml file 180619_Max.kml, created for the June 19, 2018, sampling day. Double-clicking a second kml file will open that file, along with any others already open in GEP.

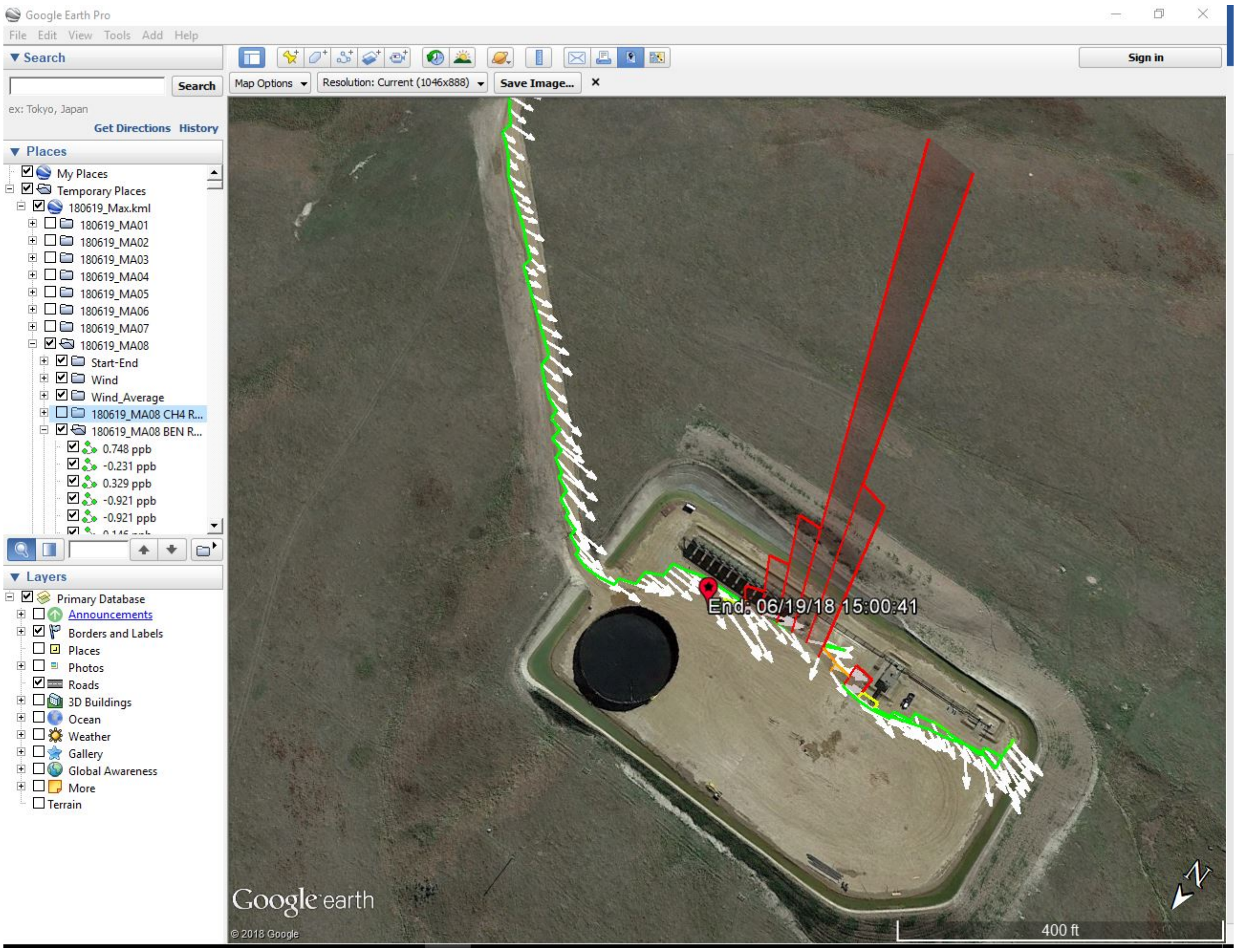

Figure 2. Screen shot of Google Earth Pro image displaying GMAP data
Fort Berthold Advanced Monitoring 2018
Fort Berthold Indian Reservation, North Dakota

Note: NEIC has not evaluated measurement uncertainty for these reported values.

Note the check boxes and dropdown arrows in the “Places” box. The dropdown arrows control the level of information that can be viewed in the “Places” box. **Figure 2** shows the individual mapping files located within the daily file; information for the eighth map run is visible. The check boxes control what is displayed on the GEP image. In **Figure 2**, for 180619_MA08, start-end icons, wind arrows, average wind arrow (located at the end icon), and benzene concentration bars are displayed. If the concentration data is displayed in the “Places” box, clicking a concentration bar in the image will highlight the concentration value in the “Places” box.

Clicking the drop-down arrow next to the wind check box and clicking on an individual wind arrow in the image would highlight the wind speed and direction for that wind arrow.

Upon opening 180619_Max.kml, all concentration maps, icons, and wind data are displayed simultaneously. However, all data for the view in **Figure 2** have been turned off by clicking the check box next to 180619_Max.kml so that the eighth benzene map for this day and its wind data can be examined more closely. This map shows the highest measured concentration of benzene in this mapping file. The concentration maximum scale is fixed such that it will appear as a red bar with a height of 25 meters. In **Figure 2**, all concentrations greater than the maximum-scale value are red with a height greater than 25 meters in proportion to the concentration. The green concentration bars represent values that would not represent elevated toluene concentrations. For DUVAS-generated concentrations, yellow or orange concentration bars represent values that would require some corroborating evidence to establish high confidence that they are true readings and not instrument noise outliers. Corroboration could be the presence of a known source directly upwind, concentration of other compounds at the same place, or red or higher values adjacent to the yellow bar.

GEP has features that allow the user to generate jpeg images from the image on the screen. The user can add icons with labels to the maps. Legends, titles, and other information can be added to the jpeg images.

When the wind direction is changing frequently, a measured concentration may also be from an emitted plume that has been blown back to the source. Large obstructions such as tanks also have wakes that can generate local winds opposite of the prevailing wind direction. Additionally, the wind speed and direction sensor is located on top of the moving vehicle and can be affected by the vehicle wake in some instances. The wind direction is determined with an internal magnetic compass that also may be affected by local magnetic fields. It would be prudent to closely examine all the available data, including concentration maps in the immediate vicinity for all compounds, as well as FLIR videos, air canister samples, source characteristics, and polar plots available around a source to decide where further investigation would be warranted. Currently, GMAP data is best used to screen for areas where further investigation using more traditional leak detection and repair (LDAR) techniques will be most useful.

Elevated Readings

Maximum concentration readings in each file collected by GMAP are shown in **Table 2**. GMAP files are correlated with FLIR videos and air canister samples along with well pad information and field notes in an Excel spreadsheet included in **Appendix A**. Only concentrations with associated GEP maps are shown in **Table 2**; they can be considered as concentrations elevated above background levels. Mapping concentrations meeting the threshold to appear as red bars in the kml files (as defined in “Overview of GMAP Mapping Surveys”) and appear in ***bold red italics*** in **Table 2**. The kml files for all concentrations reported in **Table 2** are in **Appendix B**.

Table 2. ELEVATED GMAP READINGS Fort Berthold Advanced Monitoring 2018 Fort Berthold Indian Reservation, North Dakota									
Log File	CH_4 (ppm)	BEN (ppb)	TOL (ppb)	ETB (ppb)	XYO (ppb)	XYM (ppb)	XYP (ppb)	SO_2 (ppb)	Delta VOC (ppb)
180618_MA01	2.79								***578***
180618_MA02	***7.45***								***304***
180618_MA03	***13.49***				129		22		***439***
180618_MA04	***5.50***				140		24		***734***
180618_MA05	2.16				130		25		***454***
180618_MA06	2.50				151		25		***339***
180618_MA07	2.18								280
180618_MA08	***35.65***				159		24	88	***686***
180618_MA09	2.24				134		25		
180618_MA10	2.62				160		27		***397***
180618_MA11	3.15				159		23		***351***
180618_MA12	***28.97***	***49***			177		29		***1276***
180618_MA13	***7.13***	***66***			144		26		***1477***
180618_MA14	***11.59***	***105***	62		154		27	79	***2987***
180618_MA15	1.95				156		27	86	***363***
180618_MA16	***10.83***	***172***	***117***		141		35		***5513***
180618_MA17	***20.77***	***460***	***333***	60	160	***121***	***55***		***14986***
180618_MA18	2.04	18			150		27		***346***
180618_MA19	***813.11***	***126***	63		162		26		***2829***
180619_MA01	***418.33***	***1360***	***1316***	***373***	***279***	***498***	***166***		***54538***
180619_MA02	***14.46***	***52***	44				21		***2040***
180619_MA03	2.55						22		***469***
180619_MA04	3.06						23		***406***
180619_MA05	2.80				129		25		***1082***
180619_MA06	2.31				132		26		***721***
180619_MA07	2.02								***939***
180619_MA08	***30.76***	***234***	***122***		137		32		***7115***
180619_MA09	***8.73***				125		25		***598***
180619_MA10	***4.61***	18			140		27	110	***619***
180620_MA01	2.36				119		25		***1164***
180620_MA02	2.54				124		27		***707***
180620_MA03	***5.27***				122		25		***638***
180620_MA04	***5.57***				139		24		***737***
180620_MA05	2.03						25		***724***
180620_MA06	2.57							116	***763***
180620_MA07	***4.30***								***442***
180620_MA08	***36.75***								***333***
180620_MA09	***82.46***								***586***
180620_MA10	2.39				140		26		***1004***
Note: NEIC has not evaluated measurement uncertainty for these reported values.									

FLIR VIDEOS

NEIC inspector Doreen Au took 66 FLIR videos of gaseous emissions during the GMAP survey. FLIR ThermaCAM™ GasFindIR, GF320, and Similar Infrared Cameras, NEICPROC/11-005, was followed during the collection of the videos. **Appendix A** contains an Excel spreadsheet with the details and locations of the FLIR images. The FLIR videos are included in **Appendix C**.

AIR CANISTERS

The four air canisters were collected following ASTM D5466-01/EPA Compendium Method TO-15/Air Sampling/Canisters, NEICPROC/11-008, by or under the supervision of Bill Squier.

NEIC chemist Bob Bohn analyzed the four air canister samples using gas chromatography-mass spectrometry (GC-MS) for TO-15 volatile organic compounds during July 2018. Reported compounds are quantitative results with uncertainties shown in the laboratory report. Uncertainty was estimated based on EPA Compendium Method TO-15 method acceptance criteria. The analytical results for the air canister samples collected and analyzed at the NEIC laboratory are contained in **Appendix D**. The details and locations of the air canister samples are included in the Excel spreadsheet in **Appendix A**.

The analytical results in **Appendix D** also include tentatively identified compounds (TICs) observed to be present in the samples. The identification was based solely on a spectrum and/or interpretation of the spectrum to a library database (e.g., Wiley, NIST, in-house), with no analysis of a certified reference standard. These compounds were the major chemical constituents in the samples. Ethane and propane are included in the TIC analysis and have no response on any GMAP instruments although they can be seen with the FLIR camera.

LABORATORY ACTIVITIES

CASE NARRATIVE

NEIC principal analytical chemist Bob Bohn received four gas canister samples from NEIC field engineer Bill Squier on July 3, 2018.

All NEIC laboratory analyses described in this report were within the scope of NEIC's ISO/IEC 17025 accreditation issued by the ANSI-ASQ National Accreditation Board (certificate No. AT-1646). Sample testing was conducted in accordance with the NEIC quality system by NEIC chemist Bob Bohn from January to July 2018, which includes canister clean check tests.

ANALYTICAL RESULTS

Tables 1 to 4 summarize EPA Compendium Method TO-15 volatile organic analytical results for gas canister samples. The following defines sample table information:

- < QL **–** indicates that the compound was not observed to be present in the sample above the stated quantitation limit;
- ppbv **–** parts per billion by volume.

The estimated uncertainty for reported compounds is ± 20% based on QC events.

EPA Compendium Method TO-15 chemical list:

1,1,1-Trichloroethane	Benzyl Chloride	Hexane
1,1,2,2-Tetrachloroethane	Bromodichloromethane	Isopropyl Alcohol
1,1,2-Trichloroethane	Bromoform	m- &/or p-Xylene
1,1-Dichloroethane	Bromomethane	Methyl Alcohol
1,1-Dichloroethylene	Carbon Disulfide	Methyl Ethyl Ketone (MEK)
1,2,4-Trichlorobenzene	Carbon Tetrachloride	Methyl Isobutyl Ketone (MIBK)
1,2,4-Trimethylbenzene	Chlorobenzene	Methyl Methacrylate

1,2-Dibromoethane	Chloroethane	Methyl Tert Butyl Ether
1,2-Dichlorobenzene	Chloroform	Methylene Chloride
1,2-Dichloroethane	Chloromethane	Naphthalene
1,2-Dichloropropane	cis-1,2-Dichloroethylene	o-Xylene
1,3,5-Trimethylbenzene	cis-1,3-Dichloropropylene	Propylene
1,3-Butadiene	Cyclohexane	Styrene
1,3-Dichlorobenzene	Dibromochloromethane	Tetrachloroethylene
1,4-Dichlorobenzene	Dichlorodifluoromethane (R12)	Tetrahydrofuran
1,4-Dioxane	Dichlorotetrafluoroethane (R114)	Toluene
2-Hexanone	Ethanol	trans-1,2-Dichloroethylene
4-Ethyltoluene	Ethylbenzene	trans-1,3-Dichloropropylene
Acetaldehyde	Formaldehyde	Trichloroethylene
Acetone	Heptane	Trichlorofluoromethane (R11)
Acrolein	Hexachlorobutadiene	Trichlorotrifluoroethane (R113)
Acrylonitrile		Vinyl Acetate
Benzene		Vinyl Chloride

Table 1

Station Number 6 Can 3070 Marathon-Myrmidon 1-2H		
Compound	**Concentration (ppbv)**	**Quantitation Limit (QL) (ppbv)**
Benzene	47.4	7.6
Cyclohexane	80.7	7.6
Formaldehyde	47.4	7.5
Heptane	136	7.6
Hexane	207	7.6
Methyl Alcohol	15.9	7.6
Toluene	31.7	7.6
TO-15 Compounds	< QL	7.0
Trichloroethene	< QL	12
m- &/or p-Xylene	< QL	15

Table 2

Station Number 7 Can 2626 Marathon-Sherman CTB USA		
Compound	**Concentration (ppbv)**	**Quantitation Limit (QL) (ppbv)**
1,2,4-Trichlorobenzene	13.8	14
Benzene	60.3	16
Cyclohexane	94.8	16
Heptane	99.1	16
Hexane	279	16
Methyl Alcohol	25.7	16
Toluene	24.6	16
TO-15 Compounds	< QL	16
Trichloroethene	< QL	24
m- &/or p-Xylene	< QL	30

Table 3

Station Number 8 Can 1353 WPX Energy - Arikara		
Compound	**Concentration (ppbv)**	**Quantitation Limit (QL) (ppbv)**
1,2,4-Trimethylbenzene	61.3	47
Benzene	544	50
Cyclohexane	1370	50
Ethylbenzene	73.9	49
Heptane[1]	2460	50
Hexane[1]	2750	50
m- &/or p-Xylene	231	96
o-Xylene	85.4	48
Toluene	292	50
TO-15 Compounds	< QL	50
Trichloroethene	< QL	75
[1] estimated value		

Table 4

Station Number 9 Can 2627[1] PetroShale US 8H Pad		
Compound	**Concentration (ppbv)**	**Quantitation Limit (QL) (ppbv)**
Benzene	76.4	50
Cyclohexane	139	50
Heptane	157	50
Hexane	341	50
Toluene	57.9	50
TO-15 Compounds	< QL	50
Trichloroethene	< QL	73
m- &/or p-Xylene	< QL	92
[1] reported results are an average of four analytical tests		

Table 5 summarizes tentatively identified compounds (TICs) observed to be present in the samples. The identification was based solely on a spectrum and/or interpretation of the spectrum to a library database (eg. Wiley, NIST, in-house), with no analysis of a certified reference standard.

Table 5

Station Number (Can Number)	Tentatively Identified Compound
6 (3070)	Propane
	Isobutane
	Butane
	2-Methylbutane
	Pentane
	2-Methylpentane
	Methylcyclopentane
7 (2626)	Ethane
	Propane
	Isobutane
	Butane
	2-Methylbutane
	Pentane
	2-Methylpentane
	Methylcyclopentane
	2-Methylhexane
8 (1353)	Ethane
	Propane
	Isobutane
	Butane
	2-Methylbutane
	Pentane
	Methylcyclobutane
	2-Methylpentane
	Methylcyclopentane
	2-Methylhexane
	3-Methylhexane
	Isopropylcyclobutane
	1,1,2,2-Tetramethylcyclopropane
	2-Methylheptane
	Octane
9 (2627)	Propane
	Isobutane
	Butane
	2-Methylbutane
	Pentane
	2-Methylpentane

FACT SHEET ON METHANE AND WASTE PREVENTION RULE

OVERVIEW: The Bureau of Land Management (BLM) has updated its regulations to reduce the waste of natural gas from flaring, venting, and leaks from oil and gas production operations on public and Indian lands. The final requirements, which will be phased in, will help curb waste of our nation's natural gas supplies; reduce harmful air pollution, including greenhouse gases; and provide a fair return on public resources for federal taxpayers, Tribes, and States.

The BLM's final rule requires oil and gas producers to take commonsense and cost-effective measures to reduce this waste of gas, modernizing the existing, more than 30-year-old oil and gas production rules and bringing them in line with technological advances in the industry. In addition, the rule modifies the existing royalty rate provisions to better align with the BLM's authority and enhance flexibility, but the rule would not raise royalty rates.

FACT: The BLM's onshore oil and gas management program is a major contributor to our nation's oil and gas production. Domestic production from almost 100,000 federal onshore oil and gas wells accounts for five percent of the nation's oil supply and eleven percent of its natural gas. In Fiscal Year 2015, the production value of this oil and gas was worth almost $21 billion and generated over $2 billion in royalties.

FACT: Large quantities of natural gas are wasted during oil and gas production. Between 2009 and 2015, oil and gas producers on public and Indian lands vented, flared and leaked about 462 billion cubic feet (Bcf) of natural gas. That's enough gas to supply about 6.2 million households for a year. These losses create a myriad of problems, including: releasing harmful emissions, including methane, into the atmosphere; safety issues, if not properly handled; and waste of a valuable domestic energy resource.

FACT: Taxpayers are losing out. States, Tribes and federal taxpayers also lose royalty revenues when natural gas is wasted – as much as $23 million annually in royalty revenue for the Federal Government and the States that share it, according to a 2010 Government Accountability Office (GAO) report.

FACT: The rule minimizes waste of natural gas. The final rule will save and put to productive use up to 41 Bcf of gas a year – enough to supply up to about 740,000 households each year. Overall, the rule will reduce flaring by an estimated 49 percent and venting and leaks by roughly 35 percent (compared to 2014 rates).

FACT: Inaction is not an option. Methane, a powerful greenhouse gas about 25 times more potent than carbon dioxide, accounts for nine percent of all U.S. greenhouse gas emissions, and almost one-third of that is estimated to come from oil and gas operations. U.S. methane emissions are projected to rise substantially without additional steps to lower them. Several states, including North Dakota, Colorado, Wyoming, Utah and most recently Pennsylvania, as well as the U.S. Environmental Protection Agency (EPA), have also taken steps to limit venting, flaring and/or leaks.

<u>FACT:</u> The rule will reduce emissions that worsen climate change. BLM estimates that this rule could avoid an estimated 175,000-180,000 tons of methane emissions per year, roughly equivalent to 4.4-4.5 million metric tons of carbon dioxide emissions. This is also roughly equivalent to eliminating the greenhouse gas emissions from 924,000 to 950,000 vehicles.

<u>FACT:</u> The rule's benefits are projected to outweigh its costs. Using conservative assumptions, the BLM estimates that the rule's net benefits could range from $46 to $204 million per year. Benefits include revenues for operators from sale of recovered natural gas and environmental benefits of reducing methane emissions and other air pollutants.

<u>FACT</u>: Impacts to operators are expected to be minimal. Many oil and gas operators are voluntarily taking steps required in the rule to reduce wasted gas and improve operations. The BLM estimates that the annual cost to industry of implementing the rule will be $110-279 million. Individual, small business operators may see profit margins reduced by less than two-tenths of one percent, on average. About 40 percent of natural gas now vented or flared from onshore Federal leases could be economically captured with currently available technologies, according to the 2010 GAO report.

<u>FACT</u>: The rule reflects stakeholder outreach through public meetings and tribal consultations. The BLM conducted public and tribal meetings in 2014 and again in 2015 during the public comment period. The BLM received over 300,000 comments on the proposed rule. The BLM has also coordinated with individual states, as well as the Environmental Protection Agency, to avoid inconsistency or redundancy in regulations.

PROPOSED RULE OVERVIEW

The Mineral Leasing Act requires the BLM to ensure that operators "use all reasonable precautions to prevent waste of oil or gas." Important elements of the proposed rule include:

LIMITING ROUTINE GAS FLARING

- Currently, there is no upper limit on how much an operator can flare. The proposal would phase in, over several years, a flaring limit per development oil well, averaged across all of the producing wells on a lease.
  - Year one limit: 7,200 thousand cubic feet (Mcf)/month/well;
  - Year two limit: 3,600 thousand cubic feet (Mcf)/month/well; and
  - Year three limit (and thereafter): 1,800 thousand cubic feet (Mcf)/month/well.
- Estimated to affect about 16% of existing wells, which account for about 87% of gas flared.
- Applies only to flared associated gas from production wells, not flaring from exploration or wildcat wells or during emergencies.
- Provides an exemption if meeting the limit would cause an operator to cease production and abandon significant recoverable oil reserves under a lease.
- Operators could comply with the proposed flaring limits by: expanding gas-capture infrastructure (e.g. installing compressors to increase pipeline capacity, or connecting wells to existing infrastructure through gathering lines); adopting alternative on-site capture technologies (e.g. compressing the natural gas or stripping out natural gas liquids and trucking the product to a gas processing plant); or temporarily slowing production at a well to minimize losses until capture infrastructure is installed.
- Also improves disclosure of flared volumes by requiring metering when flared volumes reach 50 Mcf/day.

PRE-DRILLING PLANNING FOR GAS CAPTURE

- Currently, there is no mechanism to better align timing of well development and pipeline installation.
- Before drilling a development oil well, operators would need to evaluate opportunities for gas capture and prepare a waste minimization plan, which must be submitted with an Application for Permit to Drill.
- The plan must meet various requirements, and must be shared with midstream gas capture companies to facilitate timely pipeline development, but plan details would not be enforceable elements of the permit to drill.

DETECTING LEAKS

- The proposed rule will require operators to use an instrument-based leak detection program to find and repair leaks. Operators could use infrared cameras or other methods approved by the BLM; smaller operators (fewer than 500 wells) could alternatively use portable analyzers assisted by audio, visual and olfactory inspection.
- Operators would begin by inspecting twice a year. If they consistently find few leaks, they would be allowed to inspect annually, while if they consistently find more leaks, they would be required to inspect quarterly.

- The proposal is similar to EPA's recent proposed rule requiring leak detection and repair for new wells and facilities, as well as leak detection and repair requirements in Colorado and Wyoming.

REDUCING VENTING

- Except in narrowly specified circumstances, operators would be prohibited from venting natural gas. Exceptions include emergencies and venting from certain equipment subject to proposed limits.
- Operators would have to replace all "high bleed" pneumatic controllers with "low bleed" controllers within one year in most instances, tracking requirements in Colorado and Wyoming.
- Operators would generally have to replace certain pneumatic pumps with solar pumps, if adequate for the function, or route the pumps to a flare (if one is available on-site), similar to Wyoming and proposed EPA requirements for new and/or existing pumps.
- Within six months of rule's effective date, operators would have to capture or flare gas from storage tanks that vent more than six tons of volatile organic compounds (Volatile Organic Compounds)/year. This is expected to affect fewer than 300 tanks and is similar to EPA requirements for new tanks and Colorado and Wyoming requirements for new and existing tanks.
- Operators of new wells (drilled after rule's effective date) would generally not be allowed to purge those wells into the atmosphere; and operators unloading liquids from existing wells would be required to use best management practices.
- Operators would be required to capture, flare, use, or re-inject gas released during well completions. This would affect only conventional well completions, assuming that EPA finalizes its proposed rule for all hydraulically fractured well completions and recompletions.

CLARIFYING AND REVISING ROYALTY RATES

- The proposal revises existing royalty provisions for onshore oil and gas leases to specify a royalty rate at or above 12.5 percent for new competitive leases, consistent with the statutory authority in the Mineral Leasing Act.
- This modifies the existing regulation, which sets the rate at 12.5 percent and leaves the BLM no discretion to raise the rate as conditions change.
- The proposal responds to findings and recommendations in audits from the Government Accountability Office and Department of Interior Office of Inspector General.
- The BLM does not currently propose to raise royalty rates for new competitive leases.
- The proposed rule also clarifies that royalties would apply only to gas flared from wells already connected to gas capture infrastructure. This reduces burden on operators to submit applications for approval to flare royalty-free.

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Regulatory Impact Analysis for:

Revisions to 43 CFR 3100 (Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and Gas Operations)

Additions of 43 CFR 3178 (Royalty-Free Use of Lease Production) and 43 CFR 3179 (Waste Prevention and Resource Conservation)

U.S. Bureau of Land Management

November 10, 2016

Contents

Acronyms and Abbreviations

AFMSS	Automated Fluid Minerals Support System
AOFP	Absolute Open Flow Potential
APD	Application for Permit to Drill
API	American Petroleum Institute
AQCC	Colorado Air Quality Control Division
Bcf	Billion Cubic Feet
BLM	Bureau of Land Management
BTU	British Thermal Unit
CA	Communitized Agreement
CBM	Coalbed Methane
CFR	Code of Federal Regulations
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CTG	EPA Control Technique Guidelines
DPHE	Colorado Department of Public Health and Environment
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FRFA	Final Regulatory Flexibility Analysis
GAO	Government Accountability Office
Gg	Giga gram (or 1,000 Mg or 1,000 metric tons)
GHG	Greenhouse Gas
IMDA	Indian Mineral Development Act
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
IRFA	Initial Regulatory Flexibility Analysis
LA	Lease Agreement
LDAR	Leak Detection and Repair
Mcf	Thousand Cubic Feet
Mcfd	Thousand Cubic Feet per Day
Mcfy	Thousand Cubic Feet per Year
MMbbl	Million Barrels
MMcf	Million Cubic Feet
NDIC	North Dakota Industrial Commission
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NPV	Net Present Value
NSPS	New Source Performance Standards
NTL-4A	Notice to Lessees 4A
OIRA	Office of Information and Regulatory Affairs
OMB	Office of Management and Budget
ONRR	Office of Natural Resources Revenue
Psia	Pounds per Square Inch Absolute
RFA	Regulatory Flexibility Act

SBREFA	Small Business Regulatory Enforcement Fairness Act
SC-CH_4	Social Cost of Methane
SC-$C0_2$	Social Cost of Carbon
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
TSD	Technical Support Document
UGRB	Upper Green River Basin
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit
2015 GHG Inventory	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013
2016 GHG Inventory	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

1. Executive Summary

1.1 Summary of Final Rule

This analysis examines the regulatory impacts of the Bureau of Land Management's (BLM) final rule, which updates 43 CFR Part 3100 (Onshore Oil and Gas Leasing) and 43 CFR Part 3160 (Onshore Oil and Gas Operations) and creates new regulations 43 CFR Chapter II, Subpart 3178 (Royalty-Free Use of Lease Production) and Subpart 3179 (Waste Prevention and Resource Conservation). Subparts 3178 and 3179 update and replace the BLM's existing policy document Notice to Lessees-4A (or "NTL-4A").

The final rule revises 43 CFR 3103.3-1, which governs royalty rates applicable to onshore oil and gas leases, to make the rule text parallel to the BLM's statutory authority, which specifies that competitively-issued BLM-administered leases require "payment of a royalty at a rate of not less than 12.5 percent in amount or value of the production removed or sold from the lease." 30 U.S.C. § 226(b)(1)(A). The revised provision makes clear that for competitive leases issued after the effective date of this rule, the BLM has the flexibility to set rates at or above 12.5 percent, but the final rule does notset a new rate for competitive leases.

The final rule revises 43 CFR Part 3160 to require an operator, when submitting an Application for Permit to Drill (APD) for a development oil well, to also prepare and submit a Waste Minimization Plan. Preparation of a Waste Minimization Plan ensures that the operator carefully considers and plans for how it will capture the gas that will be produced, before the operator drills a well.

Subpart 3178 addresses the circumstances in which oil and gas produced from Federal and Indian leases may be used royalty-free. This subpart sets forth the general rule that royalty is not due on oil or gas that is produced from a lease or communitized area and used for operations and production purposes (including placing oil or gas in marketable condition) on the same lease or communitized area without being removed from the lease or communitized area (CA). The rule identifies uses of produced oil or gas that will and will not require prior written BLM approval for royalty-free treatment.

Subpart 3179 prohibits venting of natural gas, except under certain specified conditions, such as in an emergency or when flaring is technically infeasible. With respect to flaring, the rule requires operators of development oil wells to reduce wasteful flaring of gas by capturing for sale or using on the lease a percentage of their gas production. The rule provides for a base level of "allowable" flaring that ramps down over time, and it specifies a required capture percentage, which applies to the operator's volume of flaring adjusted to remove the allowable flaring, and which increases over time. The rule gives operators the option to meet their capture targets on a lease-by-lease basis, or on an average basis over all of their Federal or Indian production from development oil wells county-by-county or State-by-State.

Subpart 3179 also requires operators to conduct an instrument-based leak detection and repair (LDAR) program. The rule allows operators to use optical gas imaging equipment, portable analyzers deployed according to EPA's Method 21, or an alternative leak detection device approved by the BLM. The rule requires operators to conduct semi-annual inspections at well sites and quarterly inspections at compressor stations. Operators may also request BLM approval of an

alternative instrument-based leak detection program. Operators must repair a leak within 30 days of discovery, absent good cause, and verify that the leak is fixed.

Subpart 3179 also includes requirements to update old, inefficient equipment and to follow best practices to minimize waste through venting. These provisions address gas losses from pneumatic controllers and pumps, storage vessels, liquids unloading, and well drilling and completions. As a practical matter, many of the requirements will impact only existing equipment or facilities that are not regulated by the Environmental Protection Agency's (EPA) New Source Performance Standards (NSPS) Subpart OOOO or Subpart OOOOa.

In addition, subpart 3179 includes provisions specifying when lost gas is considered unavoidably lost, and royalty-free, and when it is considered avoidably lost and subject to royalties. Other provisions of subpart 3179 include requirements for measuring volumes of flared gas and reporting gas losses to ONRR.

1.2 Need for Regulatory Action

Circular A-4, the Office of Management and Budget's (OMB) guidance on the development of regulatory analyses under Executive Order 12866, instructs Federal agencies to explain the need for the policy action, whether to correct a significant market failure, such as an externality, or to meet some other compelling public need, such as improving governmental processes.

A 2010 GAO investigation and our subsequent analysis show that a large amount of natural gas is being wasted through venting and flaring at oil and gas production sites on Federal and Indian lands, despite the fact that much of this gas could be economically captured and delivered to the market. The GAO estimated that, in 2008, about 128 billion cubic feet (Bcf) of natural gas was either vented or flared from Federal leases, about 50 Bcf of which was economically recoverable (about 40% of the total volume lost). The GAO estimated that the economically recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon dioxide equivalent (CO_2e) emissions.[1]

The GAO recommended that the BLM improve its data collection to ensure a complete and accurate picture of vented and flared gas, and revise its guidance to operators requiring the use of capture technologies when the capture of gas is economically viable. The GAO identified specific technologies and practices as being "generally considered technically and economically feasible," including reduced emissions completions during drilling and completion operations, plunger lift systems for wells requiring liquids unloading, vapor recovery units to capture gas from crude oil and condensate storage tanks, flash tank separators and glycol circulation optimization for dehydration units, and low-bleed pneumatic devices (GAO 2010, pp. 7-8).

When gas is wasted rather than captured and brought to market, society loses the opportunity to use the resource and social benefits are not maximized. In addition, when the wasted gas in question comes from the Federal or Tribal mineral estate, the public or Tribes often lose royalty revenues.

[1] The BLM's estimates smaller volumes of annual gas loss through venting and flaring, but we recognize that a substantial volume of gas is being lost despite being economically recoverable.

Additionally, State governments do not receive the compensation they are owed through royalty sharing from Federal production.

Wasting gas also produces air pollution, which imposes costs to society that are not reflected in the market price of the gas. Gas that is vented to the atmosphere or flared contributes greenhouse gas (GHG), volatile organic compound (VOC), and hazardous air pollutant emissions that have negative climate, health, and welfare impacts. These uncompensated costs to society are referred to as negative externalities.

Several market inefficiencies occur when society, rather than the producer, bears the costs of pollution damage. Since the damage is not borne by the producer, it is not reflected in the market price of the commodity, and uncontrolled markets produce an excessive amount of the commodity, dedicate an inadequate amount of resources to pollution control, and generate an inefficiently large amount of pollution. With stock pollutants, like methane and carbon dioxide, which build up in the environment and cause damage over time, the burden will be greater on future generations. Further, the fact that operators do not always bear the full costs of production introduces perverse incentives to the market. Operators that voluntarily make investments to limit or avoid the loss put themselves at a competitive disadvantage in relation to operators who do not make such investments.

1.3 Summary of Results

1.3.1 Baseline Natural Gas Loss Estimates

In 2014, we estimate that 111 Bcf of natural gas was vented and flared from Federal and Indian leases. At a $4/Mcf price of natural gas, this volume has a sales value of $444 million and a royalty value of $56 million. Of the 111 Bcf, we estimate that 30 Bcf was vented and 81 Bcf was flared. We estimate that 44 Bcf of the flared gas came from the Federal and Indian mineral estates with 37 Bcf coming from the estates of other mineral owners.[2] With this analysis, the BLM estimates the costs and benefits of the requirements to reduce these losses.

Table 1.3a: Estimated Flared Gas from Federal and Indian Leases in 2014, by Mineral Ownership, Volume in Bcf

	Mineral Ownership			
Source	**Federal**	**Indian**	**Non-Federal, Non-Indian**	**Total**
Flared oil-well gas (Bcf)	26.1	15.2	35.6	76.9
Flared gas-well gas (Bcf)	2.3	0.5	1.2	4.0
Total Flaring	**28.4**	**15.8**	**36.7**	**80.9**

[2] The volumes vented and flared represent all natural gas flared from Federal and Indian leases, but the ownership of those minerals is mixed between Federal, Indian, and non-Federal non-Indian owners. In the RIA for the proposed rule, we estimated natural gas losses for 2013 to be 98 Bcf, with 22 Bcf vented and 76 Bcf flared.

Table 1-3b: Estimated Vented Gas from Federal and Indian Leases in 2014, by Source, Volume in Bcf

Natural Gas Lost Through Venting	
Source	**Volume (Bcf)**
Well completions	1.12
Pneumatic controllers	14.93
Pneumatic pumps	2.32
Gas Engines	1.06
Compressors	0.52
Liquids Unloading	3.26
Storage Tanks	2.94
Other Production (Includes Leaks)	4.01
Total Venting	**30.15**

1.3.2 Monetized Costs

This rule will require operators to incur costs to reduce flaring, replace outdated equipment, implement or contract for leak detection and repair programs, install measurement equipment, and administer these programs. With respect to equipment replacement, we expect to see the highest levels of compliance activity during the first few, transitional years of the rule. The requirements to replace existing equipment would necessitate immediate expenditures. With respect to flaring reductions, we expect expenditures to be spread over the nine-year phase-in period, and with respect to leak detetection, operators could incur upfront capital costs and lower ongoing operations costs, or annual operations costs (through hiring contractors) throughout the life of the requirements. For the purpose of this analysis, we annualize the capital costs of equipment replacement over a reasonable estimate of the functional life of the equipment (generally 10 years).[3]

After reviewing the requirements, we estimate that the rule would pose costs of about $114 – 279 million per year (with capital costs annualized using a 7% discount rate) or $110 – 275 million per year (with capital costs annualized using a 3% discount rate), as shown in Table 1.3c. These costs include engineering compliance costs and the social cost of minor additions of carbon dioxide to the atmosphere.[4] The compliance costs presented do not include potential cost savings from the recovery and sale of natural gas or natural gas liquids (those savings are shown in the summary of benefits).

We believe that the estimated costs represent the likely upper bound of potential impacts. The estimated impacts account for activities that available data suggest some operators already undertake

[3] After the initial replacement of existing equipment that would be required by this proposal, any other replacement or modification of such equipment would be subject to EPA's requirements that apply to new or modified sources – the NSPS Subpart OOOO or Subpart OOOOa.

[4] Some gas that would have otherwise been vented would now be combusted on-site or presumably downstream to generate electricity. The estimated value of the carbon additions do not exceed $30,000 in any given year.

as a matter of practice or to comply with State or local regulations that we were not able to identify and account for in this analysis.[5] To the extent that operators are already in compliance with the requirements, the estimated impacts overstate the likely actual impacts of the rule.

Table 1-3c: Estimated Annual Costs, 2017 – 2026 ($ in millions)

Requirement	Capital Costs Annualized using a 7% Discount Rate	Capital Costs Annualized using a 3% Discount Rate
Capture Target Req.	$0 – 161	$0 – 161
Flare Measurement	$4 – 7	$3 – 6
Pneumatic Controllers	$2	$2
Pneumatic Pumps	$4	$4
Liquids Unloading	$6	$5 – 6
Storage Tanks	$8	$7
LDAR	$84	$83
Administrative Burden	$7	$7
Total	$114 – 279	$110 – 275

1.3.3 Monetized Benefits

We identify the benefits of the rule as the cost savings that the industry will receive from the recovery and sale of natural gas, and the environmental benefits of reducing the amount of greenhouse gases (GHG) and other air pollutants released into the atmosphere. As with the estimated costs, we expect benefits on an annual basis.

After reviewing the requirements, we estimate that the rule will result in benefits ranging from $209 – 403 million per year. Of that amount, we estimate cost savings to the industry of about $20 – 157 million per year. We estimate a reduction in methane emissions of 175,000 to 180,000 tons per year. The monetized value of the methane reductions to be $189 – 247 million per year.

Overall, we predict the rule will reduce methane emissions by 35% from the 2014 estimates and reduce the flaring of associated gas by 49%, when the capture requirements are fully phased in.

Estimated benefits are likely lower than actual benefits. Recent studies indicate that estimated gas losses are likely higher than estimated, and if so, measures to reduce such losses would have greater impact than we project here. Also, as discussed in section 7.12 of this document, the estimates for the benefits of the LDAR requirements are developed using data from EPA's recent Control Technique Guidelines, but due to a different scope of coverage under the EPA and BLM leak control requirements, some key sources of leaks that are covered by the BLM requirements are not represented in the EPA data. Hence, the benefits of applying an LDAR program to those sources are not included in our benefits estimates (we believe their inclusion would have little impact on costs, as operators would generally already be inspecting equipment on those sites). While the

[5] Where we are aware of State regulations that already require operators to take actions required by the rule, we have removed the associated costs and benefits of those actions by operators from this analysis.

benefits estimates may also be slightly overstated due to operator compliance activities that are already occurring voluntarily or due to other regulatory requirements for which we are unable to account, we believe that this effect is probably substantially outweighed by the factors discussed above that drive underestimated benefits.

Table 1-3d: Estimated Annual Benefits, 2017 – 2026 ($ in millions)

Requirement	Cost Savings	Social Benefits[1]	Range of Annual Benefits
Capture Target Req.	$0 – 124	$0	$0 – 124
Pneumatic Controllers	$1	$19 – 25	$20 – 26
Pneumatic Pumps	$2 – 3	$29 – 37	$31 – 40
Liquids Unloading	$5 – 8	$36 – 53	$41 – 60
Storage Tanks	$0	$8 – 10	$8 – 10
LDAR	$12 – 21	$96 – 123	$109 – 143
Total	$20 – 157	$189 – 247	$209 – 403

[1] Social benefits calculated using model averages of the social cost of methane with a 3% discount rate.

1.3.4 Non-monetized Costs and Benefits

The rule is expected to have additional impacts, both costs and benefits, that this analysis examines but does not include in the calculation of monetized costs and benefits. Although the analysis monetizes the benefits of reduced methane releases and the costs of carbon dioxide additions, the analysis does not monetize the benefits to public health and the environment of reducing VOC emissions by 250,000 – 267,000 tons per year and reducing emissions of hazardous air pollutants. The rule is expected to have additional minor environmental benefits associated with the productive use of the gas downstream instead of combusting the gas upstream (due to the generally higher efficiencies associated with downstream combustion).

1.3.5 Net Benefits

The following estimated net benefits are summarized from the sections that follow. The figures presented here are in 2012 dollars, with capital costs annualized using 7% and 3% discount rates and environmental costs and benefits monetized using the social cost of of carbon and social cost of methane – using model averages of the social cost of methane with a 3% discount rate (see section 7.2).

We estimate that the rule would result in net benefits of $46 – 199 million per year (capital costs annualized using a 7% discount rate) or $50 – 204 million per year (capital costs annualized using a 3% discount rate)[6], as follows:

[6] The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented previously.

Table 1-3e: Estimated Annual Net Benefits, 2017-2026 ($ in millions)

<table>
<tr><th>Requirement</th><th>Net Benefits (with Capital Costs Annualized using a 7% Discount Rate)</th><th>Net Benefits (with Capital Costs Annualized using a 3% Discount Rate)</th><th>Non-Monetized Benefits</th></tr>
<tr><td>Capture Target Req.</td><td>($88) – $39</td><td>($88) – $39</td><td rowspan="9">Health effects of $PM_{2.5}$ and ozone exposure from annual VOC reductions;

Non-monetized climate benefits;

Health effects of reduced HAP exposure;

Minor secondary disbenefits;

Incremental environmental benefits of combusting gas downstream.</td></tr>
<tr><td>Flare Measurement</td><td>($4 – 7)</td><td>($3 – 6)</td></tr>
<tr><td>Pnumatic Controllers</td><td>$18 – 24</td><td>$19 – 25</td></tr>
<tr><td>Pneumatic Pumps</td><td>$26 – 36</td><td>$27 – 36</td></tr>
<tr><td>Liquids Unloading</td><td>$35 – 54</td><td>$36 – 55</td></tr>
<tr><td>Storage Tanks</td><td>$0 – 2</td><td>$1 – 3</td></tr>
<tr><td>LDAR</td><td>$25 – 60</td><td>$26 – 60</td></tr>
<tr><td>Administrative Burden</td><td>($7)</td><td>($7)</td></tr>
<tr><td>Total</td><td>$46 – 199</td><td>$50 – 204</td></tr>
</table>

1.3.6 Distributional Impacts

Energy System: The rule has a number of requirements that are expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases.

We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context:

- Additional natural gas production ranging from 9 – 41 Bcf per year (0.03 – 0.15% of the total U.S. production);
- A reduction in crude oil production ranging from 0.0 – 3.2 million barrels per year (0 – 0.07% of the total U.S. production).

Since the relative changes in production are expected to be small, we do not expect that the rule would significantly impact the price, supply, or distribution of energy.

Separate from the volumes listed above, we also expect 0.8 Bcf of gas to be combusted onsite that would have otherwise been vented.

Royalty: We estimate that the rule will result in annual incremental royalties of $3 – 13 million per year. Royalty payments are income to Federal or Tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important, but sometimes difficult, problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the regulation's distributional effects.[7]

Small Businesses: The BLM reviewed the Small Business Administration (SBA) size standards for small businesses, and the number of affected entities fitting those size standards, as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small businesses as defined by the SBA. As such, the rule will likely affect a substantial number of small entities.

To examine the economic impact of the rule on small entities, the BLM performed a screening analysis for impacts on a sample of expected affected small entities by analyzing the potential impact on profit margins. For the 26 companies in the screening analysis, the rule's estimated compliance costs would reduce the entities' profit margin, on average, by about 0.15 percentage points.

Based on this information, we conclude that the rule will not have a significant impact on a substantial number of small entities and a Regulatory Flexibility Analysis is not required. Nevertheless, recognizing the potential for the rule to impact a large number of small entities, some significant data limitations and uncertainties that could affect the costs of some elements of the rule, and the potential for higher or lower costs depending on operators' compliance choices and variable commodity prices, the BLM decided to conduct an Initial Regulatory Flexibility Analysis with the proposed rule and includes a Final Regulatory Flexibility Analysis with this RIA (see Section 9).

Employment: We examined the requirements and the estimated compliance costs and determined that the rule is not expected to impact the investment decisions of firms or significantly adversely impact employment. The requirements would require the one-time installation or replacement of equipment, and the ongoing implementation of a LDAR program, both of which would require labor to comply. The administrative burden required to comply with the rule (including burdens to the industry and the BLM) are monetized and included in the costs estimates provided within this analysis. The Supporting Statement for the Paperwork Reduction Act discusses the administrative burdens posed by the rule's requirements in greater detail.

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[7] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available on the web at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

2. Requirements for Analyzing the Impacts of a Regulatory Action

Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of the assessment to the OMB for review. A rule may be a significant regulatory action according to Executive Order 12866 if it would meet any of the following four criteria:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The economic analysis is to provide information allowing decision makers to determine that:

- There is adequate information indicating the need for and consequences of the action;
- The potential benefits to society justify the potential costs, recognizing that not all benefits and costs can be described in monetary or even in quantitative terms, unless a statute requires another regulatory approach;
- The action will maximize net benefits to society (including potential economic, environmental, public health and safety, and other advantages; distributional impacts; and equity), unless a statute requires another regulatory approach;
- Where a statute requires a specific regulatory approach, the action will be the most cost-effective implementation of that approach, and will rely on performance objectives to the extent feasible; and
- Agency decisions are based on the best reasonably obtainable scientific, technical, economic, and other information.

To provide this information, the economic analyses of economically significant rules will contain three elements[8]:

- A statement of the need for the action;
- An examination of alternative approaches; and
- An analysis of benefits and costs.

The Regulatory Flexibility Act (RFA) and the Small Business Regulatory Enforcement Fairness Act (SBREFA) require agencies to analyze the economic impact of regulations to determine whether there would be a significant economic impact on a substantial number of small entities.

Unless the head of the agency certifies that the rule, when promulgated, would not have a significant economic impact on a substantial number of small entities, the agency must conduct an initial

[8] OMB Circular A-4.

regulatory flexibility analysis with the proposed rule and a final regulatory flexibility analysis with the final rule.[9]

The United States Code also requires special considerations if the Office of Information and Regulatory Affairs (OIRA) of the OMB determines that the rule is "major."[10] A rule is major if it has resulted in or is likely to result in:

- An annual effect on the economy of $100 million or more;
- A major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or
- Significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.

If OIRA determines that a rule is major, then the rule may become effective 60 days after the agency promulgates it and submits it to Congress. A major rule is subject to congressional review during this time, and to other procedural requirements.[11] If OIRA determines that the rule is not major, then it becomes effective when the agency submits it to Congress.

Executive Order 13272 reinforces executive intent that agencies give serious attention to impacts on small entities and develop regulatory alternatives to reduce the regulatory burden on small entities. When the regulation will impose a significant economic impact on a substantial number of small entities, the agency must evaluate alternatives that would accomplish the objectives of the rule without unduly burdening small entities.

[9] 5 U.S.C. 603; 5 U.S.C. 604; 5 U.S.C. 605(b).
[10] 5 U.S.C. 804.
[11] 5 U.S.C. 801.

3. Background on Venting and Flaring from Oil and Gas Operations

Operators may vent natural gas during drilling and production activities (such as during well completions, liquids unloading, and emergency events where the gas cannot be flared,) or from production equipment. Some equipment uses the gas for production purposes (like pneumatic devices) while other equipment may passively vent gas either intentionally (like storage tanks) or unintentionally (if there are leaks). Depending on the circumstances, operators may also flare natural gas from onshore leases.

In this section, we describe the primary sources of vented and flared gas from oil and gas production operations, as identified by the GAO and other studies. In the sections that follow, we estimate the volumes currently vented and flared and the impacts of the rule.

A. Gas flaring from production operations, including associated gas

Associated gas (or casinghead gas) is the natural gas that is produced from an oil well during normal production operations and is either sold, re-injected, used for production purposes, vented (rarely) or flared, depending on whether the well is connected to a gathering line or other method of capture.

Production tests (or productivity tests) are "tests in an oil or gas well to determine its flow capacity at specific conditions of reservoir and flowing pressures. The absolute open flow potential (AOFP) can be obtained from these tests, and then the inflow performance relationship (IPR) can be generated."[12] The AOFP is "the calculated maximum flow rate that a system may provide in the absence of restrictions."[13] To determine an AOFP, the operator may need to flare gas (and sometimes vent) for a period of time; however, it is also possible to calculate the AOFP while capturing the gas in a sales line. For conventional oil and gas wells, well completions and production tests are separate processes temporally. For unconventional wells, however, operators may conduct production tests during flowback.

In addition, emergency flaring or venting may be necessary for safety reasons.

B. Well completions and workovers

Well completion is the process taken to transform a drilled well into a producing well. Hydraulic fracturing is a type of well completion. A well workover is "the repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons."[14] Refracturing is "an operation to restimulate a well after an initial period of production"[15] and is considered to be both a hydraulic fracturing completion and a workover.

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12 "Productivity test" as defined by the Schlumberger Oilfield Glossary.
13 "Open flow potential" as defined by the Schlumberger Oilfield Glossary.
14 "Workover" as defined by the Schlumberger Oilfield Glossary, http://www.glossary.oilfield.slb.com/en/.aspx.
15 "Refracturing" as defined by the Schlumberger Oilfield Glossary.

Releases may occur during any well completion and workover; however, greater releases are associated with "flowback" from a hydraulic fracturing completion. Flowback is "the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production."[16]

During flowback, an operator will generally return recovered fluids to a temporary 3-phase flowback separator. From the separator, the gas is diverted to a sales line or is either vented or flared, the flowback water is returned to a flowback tank (and then trucked or pumped out), and the hydrocarbon liquid is returned to a storage tank. If uncontrolled, natural gas releases may occur during any step of this process.

C. Pneumatic controllers

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure difference and temperature. Depending on the design, controllers are most often powered by pressurized natural gas, but they may also be solar-powered, powered by electricity from the grid, or powered by instrument air.

Natural gas-driven controllers come in a variety of designs for a variety of uses. Continuous bleed pneumatic controllers are those with a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control). Continuous controllers are generally classified by their bleed rate – the rate at which they continuously release gas. Low bleed continuous controllers have a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh), while high bleed continuous controllers have a bleed rate exceeding 6 scfh.

Intermittent pneumatic controllers are actuated using pressurized gas but do not bleed continuously and can serve functionally different purposes than continuous bleed controllers.

Other controllers are limited by their functionality and feasibility. Non-natural gas-driven pneumatic controllers, such as instrument air devices, can be used depending on the application, but they require electricity sufficient to power an air compressor. Mechanical controllers can replace continuous bleed controllers and intermittent controllers in many applications, but require electricity as their power source.

D. Pneumatic pumps

Pneumatic pumps are devices that use gas pressure to move or compress liquids or gases, and they are generally used at oil and natural gas production sites where electricity is not readily available. The supply gas for these pumps is most often natural gas from the production stream, though they may also use compressed air. The gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.

The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation. During chemical injection, piston pumps or diaphragm pumps will inject small amounts of chemicals to limit processing problems and protect equipment. Pneumatic

[16] "Flowback" as defined by the Schlumberger Oilfield Glossary.

pumps commonly referred to as "Kimray" pumps are used for glycol circulation and recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.

E. Liquids unloading

In producing gas wells, fluids may accumulate in the wellbore and impede the flow of gas, sometimes halting production itself. Gas wells generally have sufficient pressure to produce both formation fluids and gas early on, but as production continues and reservoir pressure declines, the gas velocity in the production tubing may not be sufficient to lift the formation fluids. When this occurs, liquids (hydrocarbons and salinized water) may accumulate in the tubing, causing a further drop in pressure, slowed gas velocity, and raised pressure at the perforations. When the bottom-hole pressure becomes static, gas flow stops and all liquids accumulate at the bottom of the tubing.

When liquid accumulation occurs, there are a number of options available to operators to remove the liquids, including:[17]

- Installing an artificial lift system or other pumping unit;
- Installing smaller diameter tubing;
- Swabbing the well to remove the fluids;
- Using a surfactant to reduce the density of the fluid column; or
- Shutting-in the well to increase bottom-hole pressure and then venting the well to the atmosphere (well purging).

We note that venting may occur during all of these interventions. Generally, lift systems reduce the volume of venting and facilitate the capture and production of gas that would otherwise be vented during purging. However, certain plunger lifts may not be connected to a gas flow line and may vent some gas in the process of unloading.

Liquid accumulation may become a recurring problem depending on the intervention that an operator uses. Lift systems, pumping units, or smaller diameter tubing, are longer lasting solutions, while swabbing, surfactants, and well purging are only temporary solutions.

F. Oil and condensate storage tanks

Crude oil and condensate tanks or vessels are used on-site to store produced hydrocarbons and other fluids. In most cases, an operator will direct recovered fluids from the well to a separator, with the hydrocarbons then directed to the storage tanks.

During storage, light hydrocarbons dissolved in the crude oil or condensate vaporize and collect in the space between the tank liquids and the tank roof. These vapors are often vented to the atmosphere when the liquid level in the tank subsequently fluctuates. Losses of gas vapors generally occur when oil is dumped into the tank, the fluids within the tank are circulated or agitated, or when

[17] An EPA document, *Lessons learned from natural gas STAR partners: Options for removing accumulated fluid and improving flow in gas wells*, describes the problem of liquid accumulation and options for removing the fluids.

the temperature changes. Lighter crude oil, with API gravity greater than 36°, typically vaporize more easily.

Rather than release these vapors to the atmosphere, an operator may install a combustion device to combust the vapors or it may install a vapor recovery unit (VRU) to capture gas vapors for sale. Capturing the gas with a VRU requires that a well be connected to a gas gathering line. VRUs have been shown to reduce VOC emissions from storage vessels by approximately 95 percent. Recovered vapors have a British Thermal Unit (Btu) content that is higher than pipeline quality natural gas. The vapors may range between 950 to 1,100 Btu per standard cubic foot, and can reach as high as 2,000 Btu/scf.

G. Leaks

Production sites with the potential for natural gas leaks include natural gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of leaks include seals, connectors, flanges, hatches, and valves, among others. Leaked gases, or evaporated liquids, are lost to the atmosphere. The leaked natural gas is lost production, and results in the release of methane, VOCs, and other air pollutants into the air.

4. Estimated Venting and Flaring on Federal and Indian Leases

4.1 GAO Investigations – Initial Estimated Losses for 2008

In 2010, the GAO released a report entitled *Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases.*[18] In this report, the GAO estimated that 126 Bcf of natural gas was vented and flared from onshore Federal leases in 2008. The sources of the lost gas accounting for that volume included: flaring from a variety of sources (28 Bcf); pneumatic devices (16 Bcf); gas well liquids unloading (17 Bcf); well completions (30 Bcf); oil and condensate storage tanks (18 Bcf); glycol dehydrators (7 Bcf); and other (10 Bcf).[19]

The GAO further concluded that about 50 Bcf of that gas could be economically captured using currently available technology, including low bleed pneumatic devices, smart automated plunger lifts, reduced emissions completions, and vapor recovery devices.[20] It estimated that 40% of the gas was economically recoverable, representing $23 million in annual Federal royalties, and 16.5 million metric tons of CO_2 equivalent emissions.[21]

Table 4-1: GAO Estimated Venting and Flaring from Federal Leases in 2008, Reduction Technologies, and Potential Reductions

Sources	Vented/ Flared Volume (Bcf)	Reduction Technology	Potential Reduction (Bcf)	Percent of Total Volume Vented/ Flared
Flared (variety of sources)	28			
Pneumatic devices	16	Use low bleed devices	9.7	7.7%
Gas well liquids unloading	17	Expanded use of smart automated plungers	7.2	5.7%
Well completions	30	Expanded use of reduced emissions completions	14.7	11.7%
Oil and condensate tanks	18	Install vapor recovery units	12.9	10.2%
Glycol dehydrators	7	Install vapor recovery devices	5.7	4.5%
Other	10			
Total	**126**		**50.2**	**39.8%**

Source: GAO 2010, pp. 12 and 20.

[18] Government Accountability Office (2010). Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases (GAO-11-34). October 2010. Available on the web at http://www.gao.gov/new.items/d1134.pdf.
[19] Ibid., p. 12.
[20] Ibid., p. 20.
[21] Ibid., highlights.

4.2 BLM Estimates for 2014

The BLM reviewed data from the Office of Natural Resources Revenue (ONRR) and 2016 GHG Inventory. Based on this review, we conclude that about 111 Bcf of natural gas was vented and flared from producing operations on Federal and Indian leases in 2014. Of that total, we estimate that 81 Bcf was flared and 30 Bcf was vented.

The ONRR flaring data further indicate that the gas flared from operations producing from Federal and Indian leases contains a mix of gas produced from various mineral estates, including Federal and Indian mineral estates and non-Federal and non-Indian mineral estates (i.e., state-owned and privately-owned minerals). Using data provided by ONRR, we estimate that, of the 81 Bcf of gas flared in 2014, about 77 Bcf of gas was flared from oil wells and 4 Bcf of gas was flared from gas wells. Further, about 44 Bcf of that total (or 55%) came from either the Federal or Indian mineral estates. The remaining 37 Bcf came from non-Federal and non-Indian mineral estates. We note that the GAO identified consistency issues with the data reported to ONRR, so the reported volume of flared gas is likely to underrepresent the actual volume flared.

Of the estimated 30 Bcf of venting, pneumatic contollers represent the bulk of the natural gas losses with fugitive emissions (including leaks), liquids unloading, and storage tanks being the sources of next highest losses. Table 4-2 shows the estimated volumes of gas loss for each source and the relative share in the context of total venting/flaring and venting alone. The sources of natural gas venting (and leaks) ranked by the percent of total vented volumes are: pneumatic controllers (49.5%), fugitives (13.3%), liquids unloading (10.8%), storage tanks (9.8%), pneumatic pumps (7.7%), well completions and workovers (3.7%), gas engines (3.5%), and compressors (1.7%).[22]

[22] In addition to these source categories, the EPA GHG Inventory provides estimates for emissions coming from natural gas gathering and boosting stations. We estimate that, while up to 13 Bcf of natural gas might potentially be emitted from these gathering and boosting stations on Federal and Indian leases, units, or communitization agreements, these sources are unlikely to be located on Federal surface lands. If located on lease, they are located after the natural gas measurement point under a rights-of-way authorization and owned by an entity other than the Federal or Indian lessee. As such, we note the potential emissions from that source but do not include it in Table 4-2.

Table 4-2: Estimated Venting and Flaring from Federal and Indian Leases in 2014

Source	Natural Gas Releases from Natural Gas Production Segment (Bcf)	Natural Gas Releases from Petroleum Production Segment (Bcf)	Vented/ Flared Total (Bcf)	Percent of Total Vented/ Flared	Percent of Total Vented
Flared Gas	3.98	76.94	80.91	72.9%	NA
Well Completions and Workovers	0.57	0.55	1.12	1.0%	3.7%
Pneumatic Controllers	7.64	7.29	14.93	13.4%	49.5%
Pneumatic Pumps	1.42	0.90	2.32	2.1%	7.7%
Gas Engines	0.75	0.31	1.06	1.0%	3.5%
Compressors	0.51	0.01	0.52	0.5%	1.7%
Liquids Unloading	3.26	0.00	3.26	2.9%	10.8%
Storage Tanks	1.54	1.40	2.94	2.6%	9.8%
Fugitives	3.39	0.62	4.01	3.6%	13.3%
Total	23.05	88.01	111.06	100.0%	

In the RIA for the proposed rule, we estimated natural gas venting of 22 Bcf in 2013. For most of the source categories, our natural gas release estimates remained relatively constant from 2013 to 2014 with two exceptions. Estimated releases from well completions were almost cut in half from 2013 to 2014. This change reflects updated GHG Inventory data on well completion emissions and tracks to EPA regulations of all well completions using hydraulic fracturing. Also, estimated releases from pneumatic controllers increased threefold from 2013 to 2014. This change reflects updated GHG Inventory data showing that intermittent controllers accounted for a much larger share of the total controllers (with continuous bleed controllers accounting for a smaller share).

In calculating the estimates for vented gas, for most of the sources, we adjusted the EPA's national emissions estimates in the 2016 GHG Inventory downward based on the share of U.S. natural gas production in 2014 that came from Federal and Indian lands (about 10.49%) and the share of U.S. crude production in 2014 that came from Federal and Indian lands (about 7.06%).[23] This top-down approach is appropriate when we expect the national emissions level to be generally representative of what we would expect on Federal and Indian lands.

We deviated from this methodology when estimating emissions for liquids unloading, opting for a bottom-up approach and basing our estimates on the regional activity data and emission factors in

[23] Data from the EPA indicate that about 448 Bcf of natural gas was vented from all U.S. onshore oil and gas production operations in 2014. Of that amount, about 291 Bcf was vented from the natural gas production segment and 157 Bcf was vented from the petroleum production segment. The breakdown of these releases, by source, is shown in the Appendix.

the 2015 and 2016 GHG Inventory.[24] For this source of losses, in particular, the GHG Inventory data suggest a high degree of variability across regions, and also within regions relevant to natural gas production on Federal and Indian lands.

The Appendix to this report contains the following related tables:

- U.S. Methane Emissions from U.S. Oil and Gas Production Segments in 2014, Estimates from the 2016 GHG Inventory;
- U.S. Onshore Dry Natural Gas and Crude Oil Production and Natural Gas and Crude Oil Production on Federal and Indian Lands, in 2014, by State Jurisdiction and National Energy Modeling System (NEMS) Region;
- Methane Emission Factors for the Natural Gas Production Stage, by Region, Data from the 2016 GHG Inventory; and
- Methane Emission Factors for the Petroleum Production Stage, Data from the 2016 GHG Inventory.

The BLM's estimates differ markedly from GAO's estimates for 2008 (shown in Section 4.1). There are several possible explanations for these discrepancies.

First, since 2010, the regulatory landscape has changed, with action on the federal and state levels. In 2012, the EPA finalized its Oil and Natural Gas Sector: New Source Performance Standards (NSPS), which established standards for EPA's regulation of volatile organic compound (VOC) emissions from "new" or "modified" sources in the oil and natural gas sectors.[25] In 2016, the EPA finalized NSPS Subpart OOOOa which addresses additional sources of emissions from new and modified sources in the oil and natural gas sectors. The NSPS regulations apply to operations nationwide, including those on Federal and Indian lands, and have a co-benefit of reducing the loss of natural gas from certain sources.

Further, several states have published regulations and policies that have impacted Federal leases in those jurisdictions. In 2014, the Colorado Department of Public Health and the Environment, Air Quality Control Division (AQCC), finalized a rule addressing venting and leaks from new and existing sources. Also in 2014, the North Dakota Industrial Commission (NDIC) approved policies aimed at reducing the flaring of natural gas from oil wells.

Second, the amount of flared oil-well gas has increased dramatically since 2008. Increased oil production from tight oil and other unconventional formations without commensurate increases to the gas transportation and processing infrastructure has led to the flaring of large volumes of associated gas.

Third, the GAO based most of its estimates for vented gas on emission factors from the EPA. However, we note that since 2010, the EPA revised its emission factors for gas well liquids

[24] In the RIA for the proposed rule, we also used a bottom-up estimation approach for well completion emissions. Since the EPA now regulates all well completions that use hydraulic fracturing, we believe that a top-down estimation is now appropriate.

[25] The EPA also finalized its National Emission Standards for Hazardous Air Pollutants (NESHAP) Review, which places certain control requirements on pneumatic pumps.

unloading and well completions. In addition to the EPA's work, additional research has focused on the loss of gas from oil and gas wells and production sites.

Lastly, regarding volumes of flared gas reported to ONRR, the GAO report identified that not all flared volumes were reported by operators. The data show that since 2008, the reported volumes of flared gas have increased quite dramatically. While these increases likely reflect the increased oil production over that period, they may also reflect the increased reporting of flared volumes. Interviews with BLM field personnel indicate that some field offices are requiring, as a condition of approval to flare, that the operator report the flared volumes to ONRR.

We note that while gas losses from oil and gas operations may have changed on an absolute or relative basis between 2008 and 2014, the GAO's conclusions about the need to expand the use of technologies to realize potential gas savings remain relevant.

5. Current Regulatory Framework

The development and production of oil and gas are regulated under a framework of Federal and State laws and regulations. Several Federal agencies implement Federal laws and requirements, while each State in which oil and gas is produced has one or more regulatory agencies that administer State laws and regulations.

State laws apply on federal lands except when they are preempted by Federal law. Accordingly, the drilling, completion, and production operations of oil and gas wells on Federal lands are subject both to Federal and to State regulation. If the requirements of a State regulation are more stringent than those of a federal regulation, for example, the operator will comply with both the State and the Federal regulation by meeting the more stringent State requirement.

Tribal and Federal laws apply to oil and gas drilling, completion, and production operations on tribal lands. Operators on tribal lands will comply with both tribal and Federal regulations by assuring that they are in compliance with the stricter of those rules.

Regardless of any difference in operational regulations, operators on Federal lands must comply with all Federal, State, and local permitting and reporting requirements. On Indian lands, they must comply with all Federal and tribal permitting and reporting requirements.

Since 2010, the regulatory landscape has changed, with action on the Federal and State levels. In 2012, the Environmental Protection Agency (EPA) finalized its Oil and Natural Gas Sector: New Source Performance Standards (NSPS) Subpart OOOO, which established standards for EPA's regulation of volatile organic compound (VOC) emissions from new, modified, and reconstructed sources in the oil and natural gas sectors. It does not address sources in existence prior to the date the NSPS was proposed, unless those sources are modified or replaced at some future time. NSPS Subpart OOOO addresses emissions from hydraulically fractured gas well completion operations, storage vessels emitting more than 6 tons per year of uncontrolled VOC, continuous bleed pneumatic controllers, and other sources. It applies to operations nationwide, including those on Federal and Indian lands, and it has a co-benefit of reducing the loss of natural gas from certain sources.

In addition, in 2016, the EPA finalized NSPS Subpart OOOOa, which addresses emissions from hydraulically fractured oil well completions, pneumatic diaphragm pumps, leaks, and other sources. Like the NSPS Subpart OOOO, this regulation addresses new, modified, and reconstructed sources in the oil and natural gas sectors, but not existing sources. It also applies to operations nationwide, including those on Federal and Indian lands, and would have a co-benefit of reducing the loss of gas from certain sources.

In October 2016, the EPA issued Control Techniques Guidelines (CTGs) to help States reduce VOCs from existing sources in certain nonattainment areas. These CTGs identify many of the same types of measures required by the OOOOa standards, but the guidelines are not a legal requirement to avoid or reduce emissions. Rather, the CTGs are a set of recommendations that State and local air pollution control agencies must consider when evaluating what they will identify as Reasonably Available Control Technology (RACT) for existing sources covered under State plans to implement

Clean Air Act requirements, known as State Implementation Plans (SIPs). States are only required to include RACT measures in their SIPs for areas whose air quality falls significantly below Clean Air Act standards for so-called criteria pollutants, such as ozone.[26]

Several States have published regulations and policies that have impacted Federal leases in those jurisdictions. Below is a summary of selected State regulations and policies that have the effect of limiting the waste of gas from production operations in the States where the production of oil and gas from Federal and Indian leases is most prevalent. Additionally, at least two States have recently expressed an intent to further reduce methane emissions through regulatory action. On February 1, 2016, California's Air Resources Board proposed new rules to reduce emissions of methane through venting and leaks during oil and gas production, processing, and storage.[27] These proposed rules would require the use of vapor collection systems and the control of vapors with 95 percent efficiency. The rules would limit the use of combustion; however, if a combustion control device must be used, the rules would require the use of a low-emissions incinerator. In January 2016, the Pennsylvania Department of Environmental Protection also announced that it would pursue an enhanced strategy for reducing methane emissions.[28]

Alaska: Historically, the State of Alaska had high rates of flaring, but the State adopted regulations in the 1970s to address the problem.[29] Since then, the State of Alaska has prohibited venting or flaring of gas except in narrowly defined circumstances: Testing a well before regular production; fuel that maintains a continuous flare; *de minimis* venting of gas incidental to normal oil field operations; and flaring or venting gas for no more than 1 hour during an emergency or operational upset. The practical effect is to drive widespread reinjection of associated gas into the field for conservation and oil recovery purposes. Alaska estimates that roughly 0.4 percent of gas production is flared, which is far lower than in most other States.

Colorado: The State has reduced venting through air quality regulations of emissions of hydrocarbons and other VOCs from the oil and natural gas industry.[30] The Colorado Department of Public Health and Environment, Air Quality Control Commission has instituted regulations similar in many ways to the EPA's existing new source performance standards (NSPS) for new and modified hydraulically fractured gas wells and gas processing facilities. The Colorado regulation incorporates some aspects of EPA's NSPS Subpart OOOO by reference, and expands upon the EPA standards in other areas. For example, the Colorado rule requires operators to control emissions from well operations (completions and recompletions) for all hydraulically fractured oil and gas wells. It extends the requirements for pneumatic controllers and storage tanks to cover existing, rather than just new, devices and facilities. It also requires operators to implement a

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[26] *I.e.*, nonattainment areas designated "moderate" or above.

[27] State of California Air Resources Board Staff Report: Statement of Reasons, available at: http://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20ISOR.pdf.

[28] Pennsylvania Department of Environmental Protection, A Pennsylvania Framework of Actions for Methane Reductions from the Oil and Gas Sector, available at: http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/DEP%20Methane%20Strategy%201-19-2016%20PDF.pdf.

[29] Alaska Regs is Alaska Administrative Code Title 20 - Chapter 25 235. Gas Disposition.

[30] Colorado Air Quality Control Commission Regulations, Regulation 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides).

comprehensive instrument-based LDAR program, sets standards for liquids unloading similar to that which the BLM is proposing, and includes other measures.

Montana: The State has had some limits on venting and flaring in place for some years.[31] Produced gas vented to the atmosphere at a rate exceeding 20 Mcf per day that continues for more than 72 hours must be burned. After completion of a gas well, no gas may be permitted to escape, except gas required for periodic testing or cleaning of the well bore. If, after well completion, the operator intends to flare gas production in excess of 100 Mcf per day, the operator must obtain a variance from the oil and gas board. The operator must submit a production test and a statement justifying the need for a variance, including information such as potential human exposure; relative isolation of location; measures to restrict public access to location; low gas volume; and low Btu content. The board may elect to restrict production until the gas is marketed or otherwise beneficially used.

North Dakota: In March 2013, the Industrial Commission of North Dakota adopted a policy to reduce flaring, and it followed this with an enforceable order adopted in July 2014.[32] The policy and order require well operators to meet flaring reduction targets according to a prescribed timeline. The gas capture targets for each operator start with a target of capturing at least 74 percent of production by October 2014 and then rise over time, culminating with a target of capturing at least 91 percent of production by October 2020.[33] The operator may show compliance with the target by well, field, county, or statewide. The policy provides for oil production to be restricted from wells where the operator does not meet the flaring reduction targets. Production is restricted to no more than 200 barrels of oil per day for those wells capturing more than 60 percent of the gas production, but less than the applicable target percentage. Production is restricted to no more than 100 barrels of oil per day from those wells capturing less than 60 percent of produced gas.

Utah: Utah approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014.[34] This GAO requires LDAR for equipment (e.g. – valves, pumps, etc.) at varying frequencies. The monitoring can be performed using Method 21 (leak definition of 500 ppm), a tunable diode laser absorption spectroscopy (leak definition of 500 ppm) or an IR camera (OGI – visible emissions indicate leak). Utah requires annual monitoring for the initial year. After the initial monitoring year, the frequencies begin to vary based on performance and vary from quarterly inspections to annual inspections. It also requires the use of low-bleed pneumatic controllers and the control or combustion of emissions from pneumatic pumps and storage tanks.

Wyoming: The Wyoming Department of Environmental Quality adopted regulations on May 19, 2015, to reduce emissions of VOCs in the Upper Green River Basin nonattainment area, which does not meet the air quality standards for ozone pollution.[35] The regulations require operators to control emissions from new and existing storage tanks with uncontrolled emissions of 4 or more tons per year, by 2017, and to control emissions from existing pneumatic pumps (as of January 1, 2014) by

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[31] Administrative Rules of Montana, Title 17-Chapter 8-Subchapter 16 Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit.
[32] https://www.dmr.nd.gov/oilgas/or24665.pdf
[33] Specifically, the targets for gas capture are: 74 percent of the gas by October 1, 2014; 77 percent by January 1, 2015; 85 percent by January 1, 2016; and 90 percent by October 1, 2020, with potential for 95 percent capture.
[34] http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf
[35] The BLM received an advanced copy of the final rule but do not have a citation with which the public can access the regulation.

2017. The regulations also require existing pneumatic controllers (as of January 1, 2014) to be low-bleed or zero-bleed by 2017, and they require operators to implement an instrument-based LDAR program with quarterly inspections, by 2017. Further, the regulations establish requirements on additional emissions sources.

6. Regulatory Action and Alternatives Considered

The section discusses specific elements of the regulation and identifies and discusses alternative policy approaches that the BLM considered. See Table 6-1 for a summary of the regulatory action and alternatives considered and Table 6-2 for a side-by-side comparison of the rule's requirements and the EPA's final NSPS regulations.

<u>Royalty Rate:</u> The rule will conform the regulations governing royalty rates for new competitive oil and gas leases on Federal lands to the corresponding statutory provisions. The language does not specify a royalty rate increase, but provides the BLM discretion to change the rate in the future. The royalty rate on existing Federal leases will remain unchanged. The royalty rate for Federal leases obtained non-competitively after the effective date of the final rule will also remain unchanged from its current level of 12.5%, as this level is specified by statute. Tribal leases will be unaffected by these revisions or any potential future changes to the royalty rate on Federal leases.

<u>Flaring of oil-well gas:</u> To reduce the amount of oil-well gas flaring, this rule requires the operator to:

- For planned oil wells, submit information about the anticipated gas production and planned gas disposition with the Application for Permit to Drill (APD);
- Limit flaring from development oil wells by meeting the following gas capture targets:
    - Year 1: No requirements;
    - Year 2: 85% capture target with 5,400 Mcf/month/well of flaring allowed;
    - Year 3: 85% capture target with 3,600 Mcf/month/well of flaring allowed;
    - Year 4: 90% capture target with 1,800 Mcf/month/well of flaring allowed;
    - Year 5: 90% capture target with 1,500 Mcf/month/well of flaring allowed;
    - Year 6: 90% capture target with 1,200 Mcf/month/well of flaring allowed;
    - Year 7: 95% capture target with 1,200 Mcf/month/well of flaring allowed;
    - Year 8: 95% capture target with 900 Mcf/month/well of flaring allowed;
    - Year 9: 95% capture target with 750 Mcf/month/well of flaring allowed;
    - Year 10: 98% capture target with 750 Mcf/month/well of flaring allowed;
- Operators may calculate capture percentages across the flaring wells it administers on a lease-by-lease basis or across a county or State;
- The BLM may approve an alternative capture target if the operator demonstrates that the specified targets would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease;
- Operators must measure rather than estimate flared volumes when the operator is flaring 50 Mcf or more of gas per day from a high pressure flare stack or manifold, based on estimated volumes from the previous 12 months, or the life of the flare, whichever is shorter; and
- Operators must pay royalty on flared gas in excess of the allowable volume. Operators would face penalties for non-compliance consistent with BLM's civil penalties procedures.

Several States have regulations specifying flaring limits. Wyoming and Utah limit flaring to 60 Mcf/well/day and 1,800 Mcf/well/month, respectively, unless the operator obtains State approval

of a higher limit.[36] North Dakota has a more comprehensive policy to limit flaring within the State. It has established escalating gas capture targets, which the operator may meet on a well, field, or State-wide basis for the wells under its control. If the operator does not meet the targets, then the State imposes production limits on the operator's crude oil production.

In the proposed rule, the BLM proposed a flaring limit to be applied on a well basis, meaning that the operator would not be able to exceed a set flaring amount (proposed as 60 Mcf/day). The approach carried forward in the final rule instead allows operators to comply with the capture targets across their flaring development oil wells in a county or State; thus allowing them to prioritize flaring reductions to locations and operations where the marginal control costs are lowest.

In developing the rule, the BLM also considered whether it should assess royalty on all flared associated gas. It did not carry forward this option after determining that an across-the-board application of royalties was not consistent with past practice and precedent. Also, the BLM considered whether to identify zones that would potentially support capture based on information provided by the operator. Under this approach, the BLM envisioned ordering the capture of 100% of the associated gas in specified capture zones if the internal rate of return (IRR) for gas projects within the zone exceeded 7%. The BLM envisioned that it would determine a timeframe for capturing gas from the area on a case-by-case basis (not to exceed 3 years). The BLM did not move forward with this alternative, due to concerns about the complexity of identifying gas capture zones and making capture determinations. Further, analysis suggested that adding this requirement in addition to the flaring limit would add significantly to the costs of the rule without significantly reducing gas waste.

<u>Flaring of gas during well testing:</u> To reduce the amount of gas flared during well testing, this rule reduces the allowed amount of gas flared royalty-free from 50 MMcf to 20 MMcf. Generally, we believe that the operator is properly incentivized and will minimize the amount of gas flared during well testing. In addition, the BLM added a provision in the final rule which allows the BLM to increase the 20 MMcf royalty-free flaring limit by up to an additional 30 MMcf of gas for exploratory wells in remote locations where additional testing is needed in advance of development of pipeline infrastructure. We did not consider alternatives to limit the flaring further.

<u>Gas loss during well drilling, completion, and workover:</u> To reduce the amount of gas lost during well drilling, this rule requires that, unless technically infeasible, the gas from drilling operations be either captured and routed to a sales line, combusted, re-injected, or used for production purposes on site. It is common industry practice to control gas during drilling operations and route the gas either to a flare or, in some cases, to a sales line. Controlling gas produced during drilling is important for safety.

To reduce the amount of gas lost during well completions, this rule requires that, unless technically infeasible, the gas from well completions be either captured and routed to a sales line, combusted, re-injected, or used for production purposes on site. This is consistent with, although less detailed

[36] Wyoming Operational Rules, Drilling Rules Section Ch. 3, Section 39(b), available at http://soswy.state.wy.us/Rules/RULES/9584.pdf; Utah R649-3-20, Gas Flaring or Venting Section 1.1, available at (http://www.rules.utah.gov/publicat/code/r649/r649-003.htm#T20. We note that the state limits trigger a review by a state review board, which then determines whether the operator must capture the gas.

than the EPA requirements in NSPS Subpart OOOO and Subpart OOOOa, which regulate gas and oil well completions using hydraulic fracturing. Those requirements already apply to operations on Federal and Indian lands. As a result, we do not expect the BLM requirements to require any additional action from an operator in compliance with subparts OOOO and OOOOa. The BLM also considered placing requirements on conventional oil and gas well completions. We did not carry that option forward, because the loss of gas from conventional well completions is very small and regulating conventional well completions is not a particularly cost-effective way to reduce waste.

<u>Gas loss from pneumatic controllers:</u> To reduce the amount of gas lost from pneumatic controllers, this rule requires that operators replace all high-bleed continuous controllers with low-bleed continuous controllers. Exceptions to the requirement are available to the operator under certain conditions.

<u>Gas loss from pneumatic diaphragm pumps:</u> To reduce the amount of gas lost from pneumatic pumps, the rule requires that operators must either replace diaphragm pumps with zero-emission pumps or route the gas releases from the pumps to processing equipment for capture and sale. Alternatively, an operator may route the exhaust to a flare or low pressure combustion device if the operator makes a determination that replacing the pneumatic diaphragm pump with a zero-emissions pump or capturing the pump exhaust is not viable because (1) a pneumatic pump is necessary to perform the function required and (2) capturing the exhaust is technically infeasible or unduly costly. If an operator makes this determination and has no flare or low pressure combustor on-site or flaring to such a device would be technically infeasible, the operator is not required to route the exhaust to a flare or low pressure combustion device. A pump is exempted from this requirement if: it is temporarily on site; the pump does not vent exhaust gas to the atmosphere, or the operator demonstrates, and the BLM concurs, the installation of controls would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves. The BLM proposed to regulate pneumatic piston pumps, but did not carry that option forward, because gas releases from piston pumps are reported to be a fraction of those from diaphragm pumps, according to the 2016 GHG Inventory.

<u>Gas loss during liquids unloading:</u> To reduce the amount of gas lost during liquids unloading, the rule requires that the operator use practices for liquids unloading operations that minimize vented gas and the need for well venting, unless the practices are necessary for safety. The rule also requires that for wells equipped with a plunger lift system or an automated well control system, the operator must optimize the operation of the system to minimize gas losses. For all wells, before the operator manually purges a well for the first time after the effective date of rule, the operator must document in a Sundry Notice that other methods for liquids unloading are technically infeasible or unduly costly. In addition, during any liquids unloading by manual well purging, the person conducting the well purging is required to be present on site to minimize to the maximum extent practicable any venting to the atmosphere. In developing the rule, the BLM considered whether it would be appropriate to require the installation of plunger lifts, but determined that such a requirement would not be technically feasible in all cases. The BLM also considered prohibiting well purging from any wells drilled after the rule's effective date but did not carry that requirement forward in the final rule due to concerns about the technical feasibility for all potential operations and scenarios.

<u>Gas loss from oil and condensate storage tanks:</u> To reduce the amount of gas vapors vented or lost from storage tanks, the rule requires that if the potential VOC emissions from a tank exceed 6 tpy, operators must route the gas vapor to a sales line. Alternatively, the operator may route the vapor to

a combustion device after determining that routing the vapor to a sales line is technically infeasible or unduly costly. The operator also may submit a Sundry Notice to the BLM that demonstrates that compliance with the above options would cause the operator to cease production on the lease due to the cost of compliance. The operator may remove the controls if VOC emissions fall below 4 tpy per tank. The EPA already imposes the same requirements on new or modified storage tanks. In developing the proposal, the BLM considered a range of thresholds.

Gas loss from leaks: To reduce the amount of gas lost from leaks, the rule requires that the operator conduct semi-annual instrument-based inspections of sites and equipment on a lease, unit, or communitized area (and quarterly inspections for compressor stations). Sites with only a wellhead or wellheads and no other equipment are exempt from the LDAR requirements.

In the RIA for the proposed rule, the BLM considered using different inspection frequencies based on the level of production from the site, e.g., sites with less gas production might require less frequent inspections (e.g., annual) while sites with greater gas production might require more frequent inspections (e.g., quarterly). In this RIA, we present alternatives that would apply annual inspections to all sites, quarterly inspections to all sites, and more specific alternatives centering around the semi-annual and annual inspection frequencies and well productivity for oil well sites.

The BLM also considered alternatives related to which leaks would require repair. The BLM considered whether to require the operator to repair only those leaks where the sales of the recovered gas would pay for the cost of the repair. The BLM also considered requiring the operator to repair leaks above a certain volume. Ultimately, the BLM proposed and carried forward with the final rule the requirement that the operator repair all detectable leaks, since the available data indicate that the vast majority of leaks can be repaired with a payback period of less than one year. We discuss the available data in detail in the examination of the alternatives.

Table 6-1: Final Requirements and Alternative Considered

Source	Distinction Within Source	Final Requirements	Alternatives Considered to the Final Requirements or Maintaining the Status Quo
Flared (variety of sources)	Oil-well gas (associated gas)	Requires operators to submit information with its APD for a development oil well about anticipated gas volumes and planned disposition of any associated gas. Requires operators to meet gas capture targets for oil wells that flare gas. The capture targets take effect in the second year of the rule and increase incrementally over time. Requires operators to measure flared associated gas from a flare stack or manifold if greater than 50 Mcf/day, monthly average. Royalty is specified on excess gas flared during production operations. Subject to the provisions in the final rule, royalty is not specified for well completion gas, well testing gas, gas used for production purposes, gas released during emergencies, gas released during liquids unloading, gas vapors emitted from storage tanks, or gas lost from leaks.	Specifying royalty on all lost gas; Flaring limits; Identifying gas capture zones and ordering the capture of gas under certain conditions.
	Well testing	Reduces maximum royalty-free volume limit to 20 MMcf, with an option for the BLM to increase the 20 MMcf royalty-free flaring limit by up to an additional 30 MMcf of gas for exploratory wells in remote locations where additional testing is needed in advance of development of pipeline infrastructure.	Increasing royalty-free flaring limit to 20 MMcf without the option to increase the limit.
Well drilling, completions, and well maintenance	Oil and gas well completions with hydraulic fracturing (no practical effect)	Requires gas from well completions to be captured and routed to a sales line, combusted, re-injected, or used for production purposes on site.	Regulating conventional well completions
Pneumatic controllers	Continuous, high bleed (practically affects existing controllers)	Requires operators to replace high-bleed continuous controllers with low-bleed controllers, with some exceptions.	None

Table 6-1: Final Requirements and Alternative Considered

Source	Distinction Within Source	Final Requirements	Alternatives Considered to the Final Requirements or Maintaining the Status Quo
Pneumatic pumps	Diaphragm chemical injection pumps (practically affects existing diaphragm pumps)	Requires operators to either replace pneumatic diaphragm pumps with zero-emission pumps or route the gas releases from the pumps to processing equipment for capture and sale, with exceptions.	Requiring replacement of piston pneumatic pumps in addition to diaphragm pneumatic pumps
Gas well liquids unloading	None	Requires various operational and reporting requirements when conducting liquids unloading.	Placing plunger lift requirements; Prohibiting well purging from new wells.
Oil and condensate storage vessels	None (practically affects existing uncontrolled tanks)	If VOC emissions exceed 6 tpy per storage vessel, requires operators to route gas vapor to a sales line. Alternatively, operators may route the vapor to a combustion device after determining that routing the vapor to a sales line is technically infeasible or unduly costly, with some exceptions.	Requiring combustion (at a minimum) at different VOC threshold; Placing VRU requirements on higher volume tanks.
Leaks	None (practically affects existing wellsite facilities)	Requires operators to implement a semi-annual LDAR program for well sites and quarterly LDAR for compressor stations. Operators must use an infrared camera, portable analyzer, or other method approved by the BLM. Operators must repair all identified leaks. Operators may request BLM approval of an alternative instrument-based leak detection program, which the BLM may approve if it finds that the program would reduce leaked volumes by at least as much as the BLM program.	Alternative inspection frequencies and mechanisms for adjusting the frequencies, including different frequencies for marginal wells.

Table 6-2: Final Requirements and Interaction with EPA's Regulations

Source	EPA Subpart OOOO	EPA Subpart OOOOa	Practical Impact of BLM's Rule
Flaring during normal production operations	None	None	Regulates operations.
Well drilling	None	None	Regulates well drilling
Well completions and workovers	Regulates hydraulically fractured gas well completions	Regulates hydraulically fractured oil well completions	None, since all well completions are "new" and compliance with Subpart OOOO and Subpart OOOOa satisfies BLM requirements.
Pneumatic controllers	Regulates new pneumatic controllers	None	Regulates pneumatic controllers installed before Subpart OOOO's implementation that are high-bleed and continuous-bleed.
Pneumatic Pumps	None	Regulates new diaphragm pneumatic pumps	Regulates diaphragm pneumatic pumps installed before Subpart OOOOa's implementation.
Gas well liquids unloading	None	None	Regulates operations.
Oil and condensate storage tanks	Regulates new or modified tanks	None	Regulates tanks existing before Subpart OOOO's implementation that have VOC emissions above 6 tpy.
Leaks	None	Regulates new and modified well sites	Regulates well sites in existence prior to Subpart OOOOa's implementation.

7. Examination of the Requirements and Alternatives

This section estimates the impacts of the requirements and the alternative approaches, where appropriate. For each requirement, we estimate the number of affected facilities and the incremental costs, production, and emissions reduction, as well as administrative costs to industry and the BLM. Those administrative costs are presented in the summary of results, in Section 9 of this analysis, and in more detail in the Supporting Statement for the Paperwork Reduction Act.

7.1 Estimating Costs, Benefits, and Net Benefits

The costs, benefits, and net benefits are estimated for each of the requirements. The costs include direct compliance costs and the social cost of additional carbon dioxide generated from the combustion of gas produced (in lieu of venting that gas). The benefits include the direct cost savings from recovered gas and the social benefit of methane reductions (from reduced venting). Net benefits are calculated as the benefits minus the costs.

All quantified reductions in emissions expressed in tons or tons per year mean short tons or short tons per year. The value of the emissions reductions, meaning the value of methane reduced or the value of carbon dioxide reduced, is calculated after converting the short ton volume to an equivalent metric ton volume (using a conversion factor of 1 short ton to 0.907185 metric ton), since the social cost of methane and carbon dioxide are expressed in dollars per metric ton (described in Section 7.2 below).

7.2 Climate Effects and Evaluation

As part of the analysis of costs and benefits, we considered the social costs and benefits of the estimated climate impacts. We estimated the quantity of methane emission reductions and monetized the social benefits of those reductions using estimates for the social cost of methane.[37] We also estimated changes in the quantity of carbon dioxide emission and monetized the social costs of those using estimates for the social cost of carbon.

We estimated the quantity of methane reductions using emissions factors and reductions data made available by the EPA. We then estimated the global value of these methane emisson reductions by applying the U.S. government's estimates of the social cost of methane, which are presented in the Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 ("IWG non-CO2 Addendum").[38] These social cost of

[37] Further, we expect that the reduction in the on-site flaring of associated gas will have small incremental environmental benefits in that large volumes of natural gas are expected to be combusted with greater efficiency in plants rather than in on-site flares. We did not measure this incremental benefit.

[38] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866, Interagency Working Group on Social Cost of Greenhouse Gases, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Interior, Department of Transportation, Department of the Treasury,

methane estimates are taken from the Marten *et al.* (2014) and are the same estimates used by the EPA in its analysis of its Subpart OOOOa final regulation (*Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources*) and its final rule for *New Source Standards of Performance for Municipal Solid Waste Landfills.*[39] We estimated the quantity of carbon dioxide emissions by estimating the expected gas capture or gas flaring in lieu of gas venting and assuming a factor of 34 tons of carbon dioxide per Bcf of gas captured/flared.[40] We estimate the global social disbenefits (i.e., costs) of CO2 emissions expected from this final rulemaking using the SC-CO2 estimates presented in the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised August 2016) ("current TSD").[41]

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m^2 of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions are estimated to have contributed to 0.97 W/m^2 of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions(EPA 2016 RIA, pp. 4-6.)

We calculated the global social benefits of methane emissions reductions expected from this rule using estimates of the social cost of methane (SC-CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. It includes a wide

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Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy (August 2016). Available at: < https://www.whitehouse.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf> Accessed 10/20/2016.

[39] Documents related to these rulemaking are available on the EPA websites at: http://www3.epa.gov/airtoxics/landfill/landflpg.html and https://www3.epa.gov/airquality/oilandgas/actions.html

[40] Emission factor derived from API 2009, p. 4-42.

[41] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Greenhouse Gases, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Interior, Department of Transportation, Department of the Treasury, Environmental Protection Agency, National Economic Council, Office of Management and Budget, and Office of Science and Technology Policy, (May 2013, Revised August 2016). Available at: < https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf> Accessed 10/20/2016

range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. The SC-CH_4 estimates applied in this analysis were presented in the Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 ("IWG non-CO2 Addendum"). These estimates were taken from Marten *et al.* (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC-CO_2), provides important context for understanding the SC-CH_4 estimates. Estimates of the SC-CO_2 have been used by DOE, EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008. The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar to the SC-CH_4, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is used to quantify the benefits of reducing CO_2 emissions, or the disbenefit from increasing emissions, in regulatory impact analyses.

The SC-CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG), that included several executive branch agencies, as well as White House offices (e.g. OMB, CEA) used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010, and they were updated in 2013 using new versions of each IAM. The 2013 update did not revisit the 2010 modeling decisions with regards to the discount rate, reference case socioeconomic and emission scenarios, and equilibrium climate sensitivity distribution. Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SC-CO_2 Technical Support Document (2010 SC-CO_2 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC-CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[42]

The 2010 SC-CO_2 TSD noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis.

[42] The 2010 SC-CO_2 TSD, as well as the additional (2013, 2015 and 2016) technical updates are all available at: https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.

Federal agencies have continued to consider feedback on the SC-CO2 estimates from stakeholders through a range of channels, including public comments rulemakings that use the SC-CO2 in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO2 methodology used by the interagency working group. Commenters have provided constructive recommendations for potential opportunities to improve the SC-CO2 estimates in future updates. In addition, OMB sought public comment on the approach used to develop the SC-CO2 estimates through a separate comment period and published a response to those comments in 2015.[43]

After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC-CO2 estimates in regulatory impact analysis while also continuing to engage in research on modeling and valuation of climate impacts. Currently, the IWG is seeking advice from the National Academies of Sciences, Engineering and Medicine on how to approach future updates to ensure that the estimates continue to reflect the best available scientific and economic information on climate change.[44] An Academies committee, "Assessing Approaches to Updating the Social Cost of Carbon," (Committee) will provide expert, independent advice on the merits of different technical approaches for modeling and highlight research priorities going forward. BLM will evaluate its approach based upon any feedback received from the Academies' panel.

To date, the Committee has released an interim report, which recommended against doing a near term update of the SC-CO2 estimates. For future revisions, the Committee recommended the IWG move efforts towards a broader update of the climate system module consistent with the most recent, best available science, and also offered recommendations for how to enhance the discussion and presentation of uncertainty in the SC-CO2 estimates. Specifically, the Committee recommended that "the IWG provide guidance in their technical support documents about how [SC-CO2] uncertainty should be represented and discussed in individual regulatory impact analyses that use the [SC-CO2]" and that the technical support document for each update of the estimates present a section discussing the uncertainty in the overall approach, in the models used, and uncertainty that may not be included in the estimates.[45] In August 2016, the IWG issued revisions to the SC-CO_2 Technical Support Document that responded to interim recommendations from the Academies regarding the presentation and discussion of uncertainty. The revision did not modify methodological decisions or change the SC-CO_2 estimates themselves. The Committee will release a final report in early 2017 with longer-term recommendations for updating the estimates.

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[43] See https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf.

[44] The Academies' review will be informed by public comments and focus on the technical merits and challenges of potential approaches to improving the SC-CO2 estimates in future updates. See https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions.

[45] National Academies of Sciences, Engineering, and Medicine. (2016). Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update. Committee on Assessing Approaches to Updating the Social Cost of Carbon, Board on Environmental Change and Society. Washington, DC: The National Academies Press. doi: 10.17226/21898. See Executive Summary, page 1, for quoted text.

The four $SC\text{-}CO_2$ estimates are: $13, $45, $67, and $133 per metric ton of CO_2 emissions in the year 2020 (2012 dollars).[46] The first three values are based on the average $SC\text{-}CO_2$ from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the $SC\text{-}CO_2$ for several discount rates are included because the literature shows that the $SC\text{-}CO_2$ is sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the $SC\text{-}CO_2$ across all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution, and while less likely than those reflected by the average SC- CO_2 estimates, would be much more harmful to society and therefore, are relevant to policy makers. The SC-CO_2 increases over time because future emissions are expected to produce larger incremental damages as economies grow and physical and economic systems become more stressed in response to greater climate change.

In August 2016, the IWG issued an Addendum to the current TSD that presents estimates of the SC-CH4 for use in regulatory impact analysis ("IWG non-CO2 Addendum").[47] As the Director of the Office of Information and Regulatory Affairs in OMB noted, "the methodology for valuing these damages and its application to regulatory cost-benefit analysis have been subject to rigorous independent peer review and public comment."[48] The IWG's SC-CH4 estimates are taken from a paper by Marten et al. (2014), which provided the first set of published SC-CH4 estimates that are consistent with the modeling assumptions underlying the SC-CO2.[49] Specifically, the estimation approach of Marten et al. used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO2 estimates. The aggregation method involved distilling the 45 distributions of the SC-CH4 produced for each emissions year into four estimates: the mean across all models and scenarios using a 2.5 percent, 3 percent, and 5 percent discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3 percent discount rate. Marten et al. also used the same rationale as the IWG to develop global estimates of the SC-CH4, given that methane is a global pollutant.

In addition, the atmospheric lifetime and radiative efficacy of methane used by Marten et al. is based on the estimates reported by the IPCC in their Fourth Assessment Report (AR4, 2007), including an adjustment in the radiative efficacy of methane to account for its role as a precursor for tropospheric ozone and stratospheric water. These values represent the same ones used by the IPCC in AR4 for calculating GWPs. At the time Marten et al. developed their estimates of the SC-CH4, AR4 was the latest assessment report by the IPCC. The IPCC updates GWP estimates with each new assessment, and in the most recent assessment, AR5, the latest estimate of the methane GWP ranged from 28-

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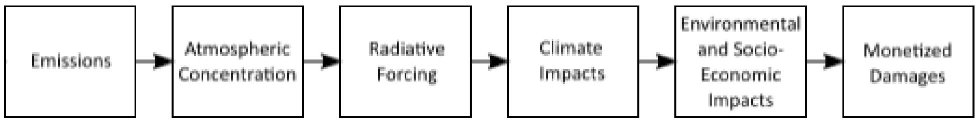
[46] Based on the current IWG Technical Support Document (AUGUST 2016), available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf_The TSD presents $SC\text{-}CO_2$ in $2007. The estimates were adjusted to 2012$ using the GDP Implicit Price Deflator, from U.S. Bureau of Economic Analysis available at: http://www.bea.gov/national/index.htm#gdp.

[47] The IWG also published estimates of the SC-N2O, which were taken from the Marten et al paper.

[48] Howard Shelanski, Jay Shambaugh, *Strengthening Tools to Account for Damages from Greenhouse Gas Emissions in Regulatory Analysis* (Aug. 26, 2016) (https://www.whitehouse.gov/blog/2016/08/26/strengthening-tools-account-damages-greenhouse-gas-emissions-regulatory-analysis).

[49] Marten *et al.* (2015) also provided the first set of SC-N_20 estimates that are consistent with the assumptions underlying the $SC\text{-}CO_2$ estimates.

36, compared to a GWP of 25 in AR4. The updated values reflect a number of changes: changes in the lifetime and radiative efficiency estimates for CO2, changes in the lifetime estimate for methane, and changes in the correction factor applied to methane's GWP to reflect the effect of methane emissions on other climatically important substances such as tropospheric ozone and stratospheric water vapor. In addition, the range presented in the latest IPCC report reflects different choices regarding whether to account for climate feedbacks on the carbon cycle for both methane and CO2 (rather than just for CO2 as was done in AR4).



Source: Marten *et al.* 2014

Figure 7-2a Path from GHG Emissions to Monetized Damages

The IWG non-CO2 Addendum discusses the SC-CH4 estimates, and compares them with other recent estimates in the literature. A direct comparison of the estimates with all of the other published estimates is difficult, given the differences in the models and socioeconomic and emissions scenarios, but results from three relatively recent studies offer a better basis for comparison (see Hope (2006), Marten and Newbold (2012), Waldhoff *et al.* (2014)). Marten *et al.* found that in general the SC-CH_4 estimates from their 2014 paper are higher than previous estimates. The higher SC-CH_4 estimates are partially driven by the higher effective radiative forcing due to the inclusion of indirect effects from methane emissions in their modeling. Marten *et al.*, similar to other recent studies, also find that their directly modeled SC-CH_4 estimates are higher than the GWP-weighted estimates. More detailed discussion of the SC-CH_4 estimation methodology, results and a comparison to other published estimates can be found in Marten *et al.*

Table 7-2b: Social Cost of Methane (SC-CH_4), 2012 – 2050 [in 2012$ per metric ton]
(Source: IWG 2016[a])

Year	SC-CH_4			
	5 Percent Average	**3 Percent Average**	**2.5 Percent Average**	**3 Percent 95th percentile**
2012	$432	$1,016	$1,405	$2,810
2015	$486	$1,081	$1,513	$3,027
2020	$584	$1,300	$1,700	$3,500
2025	$703	$1,513	$1,946	$3,999
2030	$822	$1,729	$2,162	$4,540
2035	$973	$1,946	$2,486	$5,297
2040	$1,081	$2,162	$2,810	$5,945
2045	$1,297	$2,486	$3,027	$6,594
2050	$1,405	$2,702	$3,351	$7,242

[a] The IWG (2016) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using Implicit Price Deflators for Gross Domestic Product (US Department of Commerce, Bureau of Economic Analysis), http://www.bea.gov/iTable/index_nipa.cfm

The application of the IWG's directly modeled SC-CH4 estimates to benefit-cost analysis of a regulatory action is analogous to the use of the SC-CO_2 estimates. Specifically, the SC-CH_4 estimates in Table 7-2b are used to monetize the benefits of reductions in methane emissions expected as a result of the rulemaking. Forecast changes in methane emissions in a given year, expected as a result

of the regulatory action, are multiplied by the $SC\text{-}CH_4$ estimate for that year. To obtain a present value estimate, the monetized stream of future non-CO_2 benefits are discounted back to the analysis year using the same discount rate used to estimate the social cost of the non-CO_2 GHG emission changes. In addition, the limitations for the $SC\text{-}CO_2$ estimates discussed above likewise apply to the $SC\text{-}CH_4$ estimates, given the consistency in the methodology. See the IWG non-CO_2 Addendum for additional details about the peer review conducted of the application of Marten et al. (2014) non-CO_2 social cost estimates in regulatory analysis.

Thus, the BLM is incorporating the 2016 IWG Technical Update for the $SC\text{-}CH_4$ estimates in this RIA. As previously noted, the National Academies' Committee will release a final report on opportunities to improve the SC-CO2 estimates in early 2017.While the Committee's review focuses on the $SC\text{-}CO_2$ methodology, recommendations on how to update many of the underlying modeling assumptions will also likely pertain to the $SC\text{-}CH_4$ estimates. The IWG will evaluate its approach based upon any feedback received from the Academies' panel.

7.3 Discount Rate

OMB Circular A-94 (Revised) "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs"[50] provides guidance to Federal agencies when conducting analyses, including regulatory impacts analyses. It discusses the importance of discounting future benefits and costs when computing the net present value – "discounting reflects the time value of money. Benefits and costs are worth more if they are experienced sooner. All future benefits and costs, including nonmonetized benefits and costs, should be discounted. The higher the discount rate, the lower is the present value of future cash flows. For typical investments, with costs concentrated in early periods and benefits following in later periods, raising the discount rate tends to reduce the net present value."

Circular A-94 directs agencies to use a discount rate of 7% for baseline analyses. It states, "this rate approximates the marginal pretax rate of return on an average investment in the private sector in recent years." It also recommends that agencies show sensitivity of the discounted net present value and other outcomes using additional discount rates. Literature suggests that there is a divergence between the private (considered by firms or industry) and social (considered by society) discount rates, with the private rates exceeding the social rates. This difference is considered to result from a difference in risk premiums; meaning the cost of capital is higher as the risk increases. From society's perspective, the risk may be lower or there may be no-risk, in which case a lower discount rate would be appropriate. It is common for regulatory impact analyses to analyze outcomes using a 3% discount rate, particularly for regulations with expected environmental benefits. As such, for the purposes of this analysis, we use discount rates of 7% and 3% to annualize the costs of capital investments or to present the present value of cash savings occurring in the future.

With respect to monetized benefits, we use social cost of methane estimates from IWG (2016), which provides social cost of methane estimates using model averages using a 2.5%, 3%, and 5% discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3% discount rate. For purposes of this analysis, we used the values for methane using the estimate

[50] Signed October 29, 1992. Available on the web at https://www.whitehouse.gov/omb/circulars_a094/.

deemed to be central by the IWG, i.e., the model average at 3 percent discount rate. Similarly, we used the social cost of carbon estimates provided by the Interagency Working Group on Social Cost of Carbon "3% Average." The Interagency Working Group recommends considering all four SC-CO_2estimates in the analyses, and the BLM calculated these benefits and net benefits accordingly (see Section 8.3). We note that using the other SC-CO_2estimates would result in varying benefits and net benefits. Using the 2.5% SC-CO_2discount rate would result in lower levels of monetized benefits and net benefits, while using the 5% and 95th percentil rates would result in higher levels of monetized benefits and net benefits.

7.4 Period of Analysis

The rule's requirements would impose annual costs and produce annual benefits, and we measure the impacts over a 10-year period. As discussed above, however, we do not expect the annual costs, or annual benefits, to be uniform over the life of the requirements. Rather, the first few, transitional years that these requirements are in place are expected to see the highest levels of compliance activity with respect to equipment replacement and the implementation of leak detection programs.

Beyond the initial 10-year period, we expect the provisions of the rule to have less of an impact, although the capture requirements will continue to limit flaring. For many other provisions, as existing wells and equipment are shut in or retired, new, modified and reconstructed wells and equipment would be subject to Subpart OOOO and Subpart OOOOa.

7.5 Uncertainty

The estimated costs and benefits rely on the best data that we have available to us, and modeling assumptions that we believe are reasonable, but it is important to recognize that both the inputs to the estimates and the results are subject to substantial uncertainty. Below we describe several key sources of uncertainty.

A. Commodity Price Assumptions

Different assumptions about future commodity prices produce substantially different estimates of costs and benefits. Commodity prices will affect how operators will respond to the requirements. Future commodity prices are subject to substantial uncertainty; however, we believe it is reasonable to examine the costs and benefits of this rule by using the Energy Information Administration's (EIA) future price projections and discounting those prices to account for processing and transportation costs.

With respect to the appropriate crude oil price to consider, we note that current prices are low and EIA projected prices are modestly higher. Crude oil prices in 2016 have been among the lowest in recent history, ranging from \$27/bbl to \$51/bbl.[51] At the time we prepared this analysis, the crude oil price was about \$44/bbl. The EIA's long-term price projections are \$48/bbl in 2017, \$71/bbl in

[51] Bloomberg. Cited prices are for West Texas Intermediate (WTI) Crude Oil (NYMEX). Data available at http://www.bloomberg.com/energy

2020, $85/bbl in 2025, $97/bbl in 2030, $112/bbl in 2035, and $129/bbl in 2040 with an annual growth rate from 2015 to 2040 of 4.0%.[52]

Natural gas prices in 2016 have been among the lowest in recent years, ranging from $1.64/Mcf to $2.99/Mcf.[53] At the time we prepared this analysis, the natural gas price was about $2.85/Mcf. The EIA's long-term price projections are $3.19/Mcf in 2017, $4.58/Mcf in 2020, $5.29/Mcf in 2025, $5.22/Mcf in 2030, $5.07/Mcf in 2035, and $5.02/Mcf in 2040, with an annual growth rate from 2015 to 2040 of 2.5%.[54]

Commenters on the proposed rule asserted that operators do not receive the indexed commodity prices, but rather lower prices, particularly for natural gas. Using ONRR data for 2015, we determined that it is reasonable to assume that an operator might receive prices for natural gas and crude oil that are about 75% and 98%, respectively, of the published index prices. We measured the discount to be the royalty revenues reported by ONRR divided by the royalty at 12.5% of the sales value. For processed gas and crude oil produced from Federal leases in 2015, the calculation returned 82% and 98%, respectively. Further, we compared the average sales value of unprocessed gas versus processed gas and found that price for unprocessed gas was 76% that of processed gas. Given additional feedback that the price received for natural gas could be even lower, we determined it was appropriate to assume a natural gas price that was 75% of the EIA's projections. Table 7-5, shows the projected commodity prices used in this analysis.

[52] EIA. Annual Energy Outlook, Table 12. WTI spot price. Release date May 2016. Data available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm

[53] Bloomberg. Cited prices are for Natural Gas (NYMEX). Data available at http://www.bloomberg.com/energy

[54] EIA. Annual Energy Outlook, Table 13. Natural gas spot price at Henry Hub. Release date May 2016. Prices converted from MMbtu to Mcf using a factor of 1.032. Data available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm

Table 7-5: Crude Oil and Natural Gas Price Forecasts, 2017 – 2026

Year	EIA Forecast – Crude Oil – West Texas Intermediate Spot ($/bbl)	Crude Oil Price Used in this Analysis ($/bbl)	EIA Forecast – Natural Gas – Spot Price at Henry Hub ($/Mcf)	Natural Gas Price Used in this Analysis ($/Mcf)
2017	48.08	47.12	3.19	2.39
2018	51.53	50.50	3.73	2.80
2019	64.24	62.96	4.14	3.11
2020	71.12	69.70	4.58	3.43
2021	75.37	73.86	4.47	3.35
2022	78.71	77.14	4.49	3.37
2023	81.06	79.44	4.89	3.67
2024	82.93	81.27	5.16	3.87
2025	85.41	83.70	5.29	3.97
2026	88.40	86.63	5.15	3.86
2027	92.96	91.10	4.95	3.83
2028	95.33	93.42	5.00	3.87
2029	97.06	95.12	5.05	3.91
2030	100.28	98.28	5.06	3.91
2031	103.50	101.43	5.01	3.88
2032	106.81	104.68	5.03	3.90
2033	110.31	108.11	4.98	3.85
2034	112.45	110.20	4.96	3.84
2035	116.14	113.81	4.91	3.80
2036	118.35	115.98	4.90	3.79
2037	122.09	119.64	4.84	3.74
2038	124.95	122.45	4.78	3.70
2039	129.11	126.52	4.85	3.75
2040	92.96	91.10	4.86	3.76

Source for index prices: EIA, Annual Energy Outlook 2016, Tables 12 and 13. Henry Hub natural gas prices converted from MMbtu to Mcf using a factor of 1.032.

B. Level of Voluntary Compliance

Due to the lack of available data, the analysis may not account for voluntary actions already undertaken by operators that comply with certain of the requirements. To the extent that operators are already in compliance with the requirements, the estimated impacts will overstate the actual impacts of the rule. The estimated costs and benefits of the LDAR requirements are particularly uncertain, since while many operators reportedly have some type of LDAR programs in place, we do not have data on the prevalence of these programs or on the relative costs of these existing programs compared to programs that would meet the BLM's specifications.

C. Site-Specific Characteristics

The impacts presented in this analysis are based on general emissions data and mitigation costs and may not reflect site-specific circumstances that could create significant differences in costs or benefits. We noted in the RIA for the proposed rule, that an operator's response to a requirement that restricts flaring is expected to depend on the individual characteristics of the well, and the readiness of the operator to deliver the gas to the market or bolster existing infrastructure to meet levels of production, the availability and viability of alternative capture technologies, among other factors. We believe that the approach carried forward in the final rule reduces the uncertainty about an operator's ability to meet the capture targets, because it allows the operator to prioritize the most cost-effective mitigation measure while not being confined by site-specific limitations.

D. Current Losses from Venting and Leaks

Our estimates for gas losses from venting and leaks are derived from data from the GHG Inventory. As discussed in detail in the preambles to the proposed and final rules, there is uncertainty regarding the accuracy of these estimates. In particular, several recent peer-reviewed studies suggest that these estimates underestimate, and potentially significantly underestimate, the volume of current losses from venting and leaks.

7.6 Flared Associated Gas

The final rule has several requirements to limit the flaring of associated gas from development oil wells. As presented in Section 4, according to ONRR data, operators flared roughly 81 Bcf of natural gas from BLM-administered leases in 2014. Of that amount, 77 Bcf was flared from oil wells and 4 Bcf was flared from gas wells. Further, we estimate that roughly 44 Bcf of the flared natural gas came from the Federal and Indian mineral estates and the remaining 37 Bcf came from non-Federal and non-Indian mineral estates.

This rule contains several requirements that would reduce the waste of associated gas through flaring. It establishes capture targets for natural gas coming from oil wells that operators must meet, on a lease basis or up to a statewide basis. The capture percentages apply to a volume of gas above an allowed amount of flaring, also specified by the rule. The rule establishes a schedule whereby the amount of natural gas allowed to be flared decreases over time and the natural gas capture target increases over time.

A. Flaring Allowable Volumes and Gas Capture Targets

The final rule requires operators to meet the following gas capture targets from development oil wells producing Federal or Indian minerals, either on a lease-by-lease basis or with flaring averaged across the operator's wells in a county or state.

Table 7-6a: Schedule for Flaring Allowable and Natural Gas Capture Targets

Year	Flaring Allowable (Mcf/ Well/ Month)	Capture Target - Percent (%)
2017	--	--
2018	5400	85%
2019	3600	85%
2020	1800	90%
2021	1500	90%
2022	1200	90%
2023	1200	95%
2024	900	95%
2025	750	95%
2026	750	98%

1. Background

The primary means to avoid flaring of associated gas from oil wells is to capture, transport, and process that gas for sale, using the same technologies that are used for natural gas wells. While industry continues to reduce the cost and improve the reliability of this technology, it is long-established and well understood. The capture and sale of associated gas can pay for itself where there is sufficient gas production relative to costs of connecting to or expanding existing infrastructure. Installing equipment and pipelines for capture and transport reportedly costs about $90,000 per inch-mile,[55] and therefore could cost upwards of $260,000 per mile (for a 2 and 5/8 inch diameter pipeline) or $360,000 per mile (for a 4-inch diameter pipeline).

In addition, the recent increase in flaring has encouraged entrepreneurs to develop new technologies and applications designed to capture smaller amounts of gas and put them to productive uses. Companies are beginning to experiment with and deploy several technologies as potential alternatives to the traditional pipeline systems that capture associated gas. These include: separating out natural gas liquids (NGL), which are often quite valuable, and trucking them off location; using the gas to run micro-turbines to generate power; and using small integrated gas compressors to convert the gas into compressed natural gas (CNG) that can be used on-site or trucked off location for use as transportation fuel or conversion to chemicals. In addition, there are other promising and innovative approaches that are either in development or in the earlier stages of deployment.[56]

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[55] Letter from INGAA to the California Energy Association, September 2011. Slide 46. Available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/comments/INGAA_Natural_Gas_Market_Assessment_Reference_Case_and_Scena_TN-62246.pdf. See also, Pipeline and Gas Journal, "Billions needed to meet long-term natural gas infrastructure supply, demands," April 2009. Figure 24. Available at http://pipelineandgasjournal.com/billions-needed-meet-long-term-natural-gas-infrastructure-supply-demands?page=4

[56] *See* Carbon Limits, *Improving utilization of associated gas in US tight oil fields* (April 2015) (providing detailed evaluation of new and emerging gas utilization technologies).

Natural gas contains hydrocarbons that can exist in liquid phase without being in a high pressure or low temperature environment. These are referred to as natural gas liquids (NGLs). Higher NGL concentrations in a gas stream reflect higher heating British thermal unit (Btu) value and a higher combined commodity value when the NGLs are separated from the remaining gas stream. Although NGLs are typically stripped and fractionated into their various components (e.g., propane, butane, etc.) at a gas processing plant, well-site equipment capable of stripping NGLs into a mixed liquid is available. This technology is particularly applicable in situations where high Btu associated natural gas is being flared due to lack of gas capture infrastructure. The NGLs can be stripped from the gas stream in the field, stored in tanks at the well site, and then transported by truck to a gas processing plant for sale. The remaining lower Btu gas would continue to be flared, but typically with a higher combustion efficiency than mixed gas. Conservation of the NGLs from a gas stream would reduce waste, add energy to the domestic supply, and increase royalty payments to the Federal Government and Tribal Governments.

Facilities to condense natural gas into liquefied natural gas (LNG) are more cost-effective at locations with large amounts of flaring, as relatively larger quantities of captured gas are needed to offset the cost of the LNG equipment. The surface area of well sites may need to be expanded to accommodate truck traffic and product storage needs. Also, because associated gas production drops off quickly at hydraulically fractured oil wells, LNG recovery is more likely to be cost-effective if it is implemented when production starts than if operators wait to install LNG capture equipment later in the life of the well.

Some commenters asserted that NGL recovery can only reduce 6% of flared gas volume and that it is not adequate on its own to meet the flaring limit. The commenters also estimated compliance costs based on pairing NGL with additional CNG trucking. While BLM agrees that NGL recovery only partially reduces the volume of gas left to be flared, the BLM does not agree that operators would always need to pair the technologies. As discussed above, a source could use CNG trucking without adopting NGL technologies, and given that the final rule allows operators to average flaring across multiple leases, even relatively small reductions in flaring volumes through NGL recovery may contribute to compliance with the capture targets.

On-site micro-turbines that generate electricity typically require preprocessing of the associated gas to minimize equipment maintenance issues. Generating electricity can work well if it is paired with NGL recovery, as the NGL residue gas stream is well suited as fuel for the generators. However, scaling the generators to the electricity demand that could be used locally on the well pad complicates their use. The generators may produce more electricity than is needed on site, but it may be too costly to connect to the electric grid from a remote location, as would be necessary to put the excess electricity to productive use. The cost of connecting to the electric grid depends, among other things, on the distance of the operation from the nearest electrical distribution lines. Moreover, if the electricity is used on site for production purposes, the gas used to generate the electricity would be royalty free. If the electricity produced by a micro-turbine is sold to the grid, however, the gas used to generate the electricity would incur royalties.

The CNG alternative technologies show considerable promise in effectively transporting associated gas to a centrally located processing plant while removing the higher value NGLs for other productive uses. However, limitations on the amount and rate of natural gas capture/compression on-site can limit applicability of this technology. Breakthroughs in compression technology are increasing the range of viable sites where CNG would be the preferred alternative technology. This

technology could become sufficiently attractive to reduce flaring to near zero rates, according to companies offering these services.

Carbon Limits provides an in depth comparison of these capture approaches and technologies, which we summarize here.

For pipeline infrastructure, Carbon Limits shows capital costs of $100,000 – 700,000 per mile and operating costs of $0.05 – 1.00 per Mcf. It also suggests revenues of about $2 per Mcf and a payback period of less than 1 year, depending on the situation. Procurement and installation can take months and it is not a mobile technology.[57]

For CNG, Carbon Limits shows capital costs of $400 – 2,000 per Mcf of flowrate (expressed as Mcf/day) and operating costs of $0.24 – 1.30 per Mcf produced. It also suggests revenues $5 – 6 per Mcf and a payback period of about 1 year. However, the analysis below uses substantially lower revenues from gas sales stemming from CNG trucking. Equipment can be procured within weeks and deployed to or mobilized among operations in 1 day.[58]

For NGL recovery, Carbon Limits shows low to medium capital costs of $800 – 2,500 per Mcf per day and operating costs of $0 – 0.22 per Mcf, or high costs with capital costs of $2,500 or more per Mcf per day and operating costs of $0.22 – 0.68 per Mcf. It also suggests revenues $8 – 12 per Mcf and a payback period of less than 1 year. Equipment may be procured in 15 – 24 weeks and deployed to or mobilized among operations in 1 day to 2 weeks.[59]

For gas to power, Carbon Limits shows capital costs if $1,500 – 8,000 per Mcf per day and operating costs of $0.55 – 1.68 per Mcf. It also suggests revenues $3.60 – 6.70 per Mcf and a payback period of less than 1 year. Equipment can be procured in 15 – 36 weeks and deployed to or mobilized among operations in 1 day.[60]

While these newer on-site technologies may not be suitable in all situations, in many cases they could provide a profitable alternative to using traditional pipelines for capture and sale as a way to reduce waste, and operators should consider these approaches in assessing the opportunities to reduce waste from venting and flaring.

We expect that each operator will manage the flaring oil wells in its portfolio in manner such that it will meet the gas capture targets established in this rule. If an operator expects to fall short of the gas capture target, its response is likely to vary depending on the amount of the excess flaring, the duration of the excess flaring, and its readiness to avoid the excess. For short-term excess flaring, the operator might pay royalty on the excess flared volume and take corrective action to come into compliance the next month. It might also curtail production from any of the flaring wells in its portfolio to reduce the amount of gas co-produced and flared or use alternative capture technologies like CNG or NGL stripping. We note that any curtailed production is not lost. Rather, it is deferred from the present to the future.

[57] Carbon Limits 2015a, Appendix p. 3.
[58] Ibid, p. 4.
[59] Ibid, p. 6.
[60] Ibid, p. 7-8.

2. Modeling the Impact

To analyze the impacts of potentially limiting flaring on Federal and Indian lands, the BLM requested oil and gas disposition data for all onshore activity reported to ONRR during FY 2015. This resulted in 816,231 observations with the unit of analysis being an operator's monthly volume of gas for each relevant disposition code. The data allowed for various extractions of data by date, operator, lease/unit, county, state, land class, and disposition code.

The various disposition codes describe the volumes of oil and gas that are sold, vented, flared, and used on lease among other actions. We modified the analysis over time, as early results revealed different aspects of flaring behavior on the lands of interest. One limitation of the data is in the land class. The land class types are Federal, Indian, State, Fee and Mixed. While we would like to focus on only Federal and Indian flared volumes for the purpose of this analysis, a record falls into the "mixed" category if any of the pervious varieties are in the unit/lease reported. Nearly 78 percent of the records are mixed. However; according to ONRR, about 50 percent of gas and 27 percent of oil production belongs to Federal and about 4 percent of the gas and 10 percent of the oil belongs to Indian lands.

A change from the proposed rule to the final rule includes allowing operators to group their production (at their option) across a State or county (as well as a unit/lease). As averaging the production across the State is seemingly the most advantageous to the operator, all further analysis was completed at the State level. To that end, spreadsheets were created to analyze the data state-by-state.

From the 800,000 plus records, each State specific set of records were extracted to the State spreadsheet template. For example, the North Dakota (ND) spreadsheet contains 84,604 records while the New Mexico (NM) spreadsheet has 297,268 records. Next the unique state and operator combinations were determined. For example, ND had 76 unique operators and NM had 354. To calculate a capture target percent for each operator in a State, relevant records had to be combined and then appropriately added or subtracted. We performed the calculations for each of the top flaring States: ND, NM, Wyoming (WY), Montana (MT), Colorado (CO), Utah (UT), California (CA), and South Dakota (SD). According to ONRR records, these eight States represented about 99.7 percent of the flaring reported from oil wells on Federal and Indian lands (including the mixed volumes).

We used the operator data in each state to determine the volume of flaring that would be allowed by the rule and the volume of excess flaring that would have occurred in FY 2015, for each of the specified flaring allowable volumes and capture targets shown in Table 7-6a. We then calculated the volume of excess flaring that would have occurred in FY 2015 with and without this rule in each of the eight top flaring states listed above.

In the analysis for the proposed rule, the BLM constructed several scenarios which represented likely responses of reasonable operators to the proposed flaring limits. This approach used geo-located data to group operators into response categories. These categories included the use of onsite capture (via NGL recovery), curtailment and exemptions in certain situations.

Since this final rule allows operators to average across all their oil operations, even as broadly as statewide, it becomes much more difficult to predict how operators will respond to meet the requirements for flaring reductions. Without this location information or cost data on each individual oil operator and operation, it is difficult to ascertain on which locations operators might focus to reduce flaring. Thus, in order to generate an estimate of the likely costs of reducing these flared volumes in each state, it was necessary to make certain assumptions regarding how operators could respond to the requirements to meet these capture targets.

Table 7-6b below illustrates how the percentage of the flaring controlled in each year is allocated between three avenues. These include Capacity buildout, Curtailment and CNG Trucking. First, we totaled Energy Information Administration data for pipeline outflow capacity for the Southwest and Western region over 2005 to 2015 and did a regression analysis. During this time period, the pipeline outflow capacity increased 2% per year. This growth was used to model projections going forward as the baseline for pipeline capacity.. For this RIA, capacity buildout does not carry with it any costs or benefits from this rule, as it effectively reduces the baseline of the yearly amount of flaring reduction required to be achieved by these requirements. Table 7-6c shows the amount of flaring that will be reduced by this rule as a total volume, incremental volume and an incremental increase in flaring prevented.

Table 7-6b: Percentage of Yearly Flaring Reductions Allocated to each Approach

Year	Flaring Allowable (Mcf/ month) [1]	Capture Target[2]	Capt Tar Vol Flared (Bcf)	Capacity Buildout	Curtailment	CNG Trucking
2017	n/a	0	0	0	0	0
2018	5400	85%	7.80	2%	5%	93%
2019	3600	85%	10.70	4%	10%	86%
2020	1800	90%	17.50	6%	15%	79%
2021	1500	90%	21.30	8%	20%	72%
2022	1200	90%	25.50	10%	15%	75%
2023	1200	95%	27.80	12%	10%	78%
2024	900	95%	34.40	14%	5%	81%
2025	750	95%	39.50	16%	5%	79%
2026	750	98%	40.50	18%	5%	77%

[1] Per well (averaged over all wells in a state by operator)

[2] Percent reduction required of an operators total flaring ABOVE the allowable limit

Curtailment is the first flaring reduction strategy we model for operators to meet each year's requirement for flaring reductions. The schedule for the amount of flaring reduced each year via curtailment is essentially a BLM assumption based on prices and likely operator responses. The cost of curtailment is calculated as the difference between the present value of selling oil and gas in each year versus 10 years later. A rate of 7% is used for the "opportunity cost" of oil and gas deferred. In this circumstance, operators are basically slowing their rate of production by the volume of gas necessary to meet a percentage of the flaring requirements. The associated amount of oil that would need to be deferred as a result of gas curtailment is estimated using the average Gas to Oil Ratio (GOR) for each state individually before the totals are summed together.

The analysis uses the 2016 EIA, Annual Energy Outlook for the projected prices for the modeled years 2017-2026, as well as the 10 future year's prices 2027-2036 for both oil and gas deferred. Oil and gas are valued using the West Texas Intermediate Spot Price and the Spot Price at Henry Hub for oil and gas respectively. The price operators receive for their oil was adjusted by at a rate of 98% to better reflect transportation costs. Additionally, the price operators receive for gas was adjusted by 75% to account for processing costs. Please reference section 7.5 in this RIA for an explanation of the rationale and derivation of these adjustments.

Furthermore, the BLM responded to a public commenter's suggestion that we apply an adder equivalent to 10% of the price of oil in the year of curtailment to the total cost of curtailment, to account for additional costs associated with deferring production. These additional costs could include: (1) fixed costs associated with servicing debt and other capital expenses, (2) potential penalties associated with term contracts that require providing a set volume of oil at set points in time, (3) well productivity decline from deferred production, leading to potential reduction in total recovery over the life of the well, and (4) permanent well shut-ins for wells that would need to defer significant production in order to comply with the rule.

Onsite capture is the second strategy we model for operators to reduce flaring. However, in response to public comments regarding the capacity of NGL recovery to deal with large volumes of flaring, that method of onsite capture is no longer modeled as a means by which operators would likely reduce excess flaring. We model the use of CNG trucking, as it is a low cost method of onsite capture. This analysis assumes that all reduction in excess flaring that is not addressed by the declining baseline due to capacity buildout or reduced by operators curtailing production will be achieved by CNG trucking. The costs for CNG trucking are derived from Carbon Limits (2015) which present operating costs between $0.24 and $1.30 per Mcf produced and capital costs between $400 and $2,000 per Mcf of flowrate (expressed as Mcf/day)[61].

Some commenters suggested that offload points and demand would not be sufficient to absorb increased CNG production resulting from the rule. According to the latest 2016 Annual Energy Outlook, significant growth is projected for natural gas fuel use, such as CNG and LNGs, in the transportation sector. In the 2016 AEO reference case, natural gas use in the transportation sector grows nearly 800% from current levels of 66 tBtus to 591 tBtus in 2040. Moreover, this significant growth in demand is projected to ramp up in the mid 2020s when the full flaring limits of this rulemaking are taking full effect. Therefore, the potential increase in supply of CNG from the rule is complemented by a corresponding uptick in market demand. For comparison, the incremental levels of CNG anticipated in this rulemaking, and demonstrated in RIA table 7-6b, is approximately 31 Bcf (~32 tBtus) relative to the growth of nearly 525 tBtus anticipated for natural gas use in the transportation sector. These CNG levels reflect the RIA assumptions that are illustrative compliance scenarios used in BLM's cost analysis. There is no regulatory requirement that flaring limits be met with this particular technology or at this particular level.

Since gas is captured and sold with CNG trucking[62], operators have cost savings from the sale of this gas, which can offset the cost of the onsite capture.

[61] Carbon Limits (April 2015) *Improving utilization of associated gas in US tight oil fields Appendix* page 4.
[62] The Environmental Assessment that BLM prepared for the final rule also measured the potential number of truck miles travelled and the associated carbon dioxide emissions. These estimated secondary effect impacts of about 5,700 tons per year of CO_2 emissions could pose social costs of up to $300,000 per year, depending on the year, using the model average at the 3% discount rate.

Table 7-6c: Summary of Excess Natural Gas Flared Addressed by the Rule

Year	Flaring Allowable (Mcf/ Well/ Month)	Capture Target - Percent	Flared Volumes from Operations Not Achieving the Capture Target (Bcf)	Total Flaring Prevented (%)[1]	Incre-mental Flared Volumes Addressed (Bcf)	Incre-mental Increase in Flaring Prevented (%)
2017	--	--				
2018	5400	85%	7.8	9.4%	7.8	9.4%
2019	3600	85%	10.7	13.0%	2.9	3.5%
2020	1800	90%	17.5	21.3%	6.8	8.3%
2021	1500	90%	21.3	25.8%	3.8	4.6%
2022	1200	90%	25.5	31.0%	4.2	5.1%
2023	1200	95%	27.8	33.7%	2.2	2.7%
2024	900	95%	34.4	41.7%	6.6	8.0%
2025	750	95%	39.5	48.0%	5.1	6.2%
2026	750	98%	40.5	49.1%	0.9	1.1%

[1] Based on Total Flaring in FY 2015. Data Reported to ONRR of 82.4 Bcf.

3. Results

Table 7-6d presents the total costs of the flaring reductions, cost savings from gas sales in the CNG trucking portion of reductions, as well as the net benefits of the flaring reductions when these cost savings are taken into account.

<u>Final Capture Requirements:</u>

Estimated annual impacts:

- Pose costs of about $0 to $110 million per year (low CNG costs assumed) or $0 to $162 million per year (high CNG costs assumed);
- Pose cost savings of about $0 to $124 million per year;
- Increase natural gas production by 0 – 31 Bcf per year.
- Result in net benefits ranging from -$46 to $39 million per year (low CNG costs assumed) or -$88 to $0 million per year (high CNG costs assumed).

Estimated total impacts over the 10-year evaluation period:

- Pose total costs of about $371 to $615 million (NPV using a 7% discount rate) or $483 to $798 million (NPV using a 3% discount rate);
- Pose total cost savings of about $398 million (NPV using a 7% discount rate) or $520 million (NPV using a 3% discount rate);
- Increase natural gas production by 176 Bcf between 2018 and 2026.
- Result in net benefits ranging from -$217 to $26 million per year (NPV using a 7% discount rate) or -$278 to $37 million per year (NPV using a 3% discount rate).

Table 7-6d: Estimated Annual Costs, Cost Savings and Net Benefits, 2017 – 2026 ($ in millions)

Year	Annual										2017 - 2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Flaring Allowable [1]	n/a	5400	3600	1800	1500	1200	1200	900	750	750		
Capture Target [2]	0	85%	85%	90%	90%	90%	95%	95%	95%	98%		
Estimated Costs ($ in million)												
(Low)	$0.0	$3.9	$8.4	$43.3	$92.4	$110.4	$84.4	$69.2	$89.2	$92.9	$371	$483
(High)	$0.0	$19.8	$28.6	$73.8	$126.1	$152.5	$132.1	$130.5	$157.9	$161.5	$615	$798
Cost Savings from Gas Sales	$0.0	$20.2	$28.6	$47.6	$51.4	$64.5	$79.5	$107.8	$123.9	$120.4	$398	$520
Estimated Net Benefits ($ in million)												
(Low)	$0.0	$16.4	$20.2	$4.2	-$41.0	-$45.9	-$5.0	$38.6	$34.7	$27.4	$26	$37
(High)	$0.0	$0.5	-$0.1	-$26.2	-$74.7	-$88.0	-$52.6	-$22.6	-$33.9	-$41.1	-$217	-$278

[1] Per well (averaged over all wells in a state by operator)

[2] Percent reduction required of an operators total flaring above the allowable limit

B. Flare Measurement Requirements

The rule requires the measurement of flared volumes when gas flaring meets or exceeds 50 Mcf/day for a flare stack or manifold. Operators may comply with this requirement using either a meter or measuring the GOR as specified by the rule.

According to BLM field engineers, a "thermal mass meter" would be sufficient to meet the measurment requirement using a meter and that the cost of a thermal mass meter ranges between $4,000 and $6,000. We received comments that we should also take into account the installation costs of the meter, which one commenter (referencing an EPA manual) suggested to be 1.92 times the cost of the device. If we consider the midpoint of the metering equipment to cost $5,000, then the additional 1.92 surcharge for installation and setup would take the total capital investment to about $9,600.[63] Given the $9,600 capital investment and an estimated $500 per year in operating costs,[64] assuming an equipment life of 10 years, the cost per meter is about $1,867 per year when we annualize the capital costs using a 7% interest rate or $1,625 per year when we annualize the capital costs using a 3% interest rate.

In addition, operators may comply by measuring the GOR using permanent equipment on lease. The costs of these equipment are generally considered to be less than that of the meter, but for the purpose of this analysis, we use the meter costs listed above for calculating costs of the rule.

Many operations are already set up to measure GOR. For example, according to BLM engineers in North Dakota, operations within the state should be set up to measure GOR in order to comply with the state's accounting requirements. For such operations, the operator would be able to comply with the BLM measurement requirements without making any adjustments to their site.

We estimated that operators will need to install meters on about 1,840 existing flare stacks or manifolds and about 184 new flare stacks or manifolds per year. From the total number of leases with oil-well gas flaring where we had well count data (removing ND leases since we understand that operations should already be equipped to measure GOR), we made assumptions about the number of flares required based on the number of wells on a lease. We then scaled the total up to account for the leases where we did not have well count data. The result of this process is an estimated 1,840 required meters for leases with existing flares. For the number new meters required, we assumed 10% of that number would be required in out years.[65]

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[63] We note that the commenter also suggested that an "ultrasonic time-of-flight" meter would be more expensive, costing $20,000 for the device and about $38,000 for the device plus installation. However, as stated, the BLM engineers believe that a less expensive thermal mass meter is more than sufficient.

[64] We note that the same commenter suggested that this operating cost figure was low. However, the commenter did not provide a different cost estimate and, indeed, used the $500 operating cost figure in its cost formulation.

[65] We made a similar assumption in the RIA for the proposed rule and believe that it is still valid.

Table 7-6e: Estimated Number of Flare Measurement Required for Existing Leases

Lease Size Category	Assumed Flare(s) Per Lease	Number of Flare Measurement Equipment Required for Existing Leases	Number of Flare Measurement Equipment Required for Existing Leases (excluding ND)
Single well leases	1	1,036	258
2-4 well leases	1	461	141
5-10 well leases	1.5	255	94
11-20 well leases	2	112	88
21-30 well leases	3	60	51
31-40 well leases	4	92	88
41-50 well leases	5	35	35
51-100 well leases	7.5	120	118
101-200 well leases	15	150	146
201-300 well leases	25	125	125
301-400 well leases	35	-	-
401-500 well leases	45	45	45
Total for matched leases		2,491	1,189
Total adjusted for unmatched lease/units		3,586	1,840

We estimate the following impacts for the flare measurement requirements.

Estimated annual impacts:

- Impact about 1,840 operations in 2017 with that number increasing on an annual basis to an estimated 3,680 operations in 2026;
- Pose compliance costs ranging from \$4 – 7 million per year (capital costs annualized with a 7% discount rate) or \$3 – 6 million per year (capital costs annualized with a 3% discount rate).

Estimated total impacts over the 10-year evaluation period:

- Pose total costs of \$34 – 39 million (NPV using a 7% discount rate) or \$40 – 46 million (NPV using a 3% discount rate).

Table 7-6f: Estimated Impacts of Flare Measurement Requirements

YEAR	Annual Costs 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Impacted operations												
Existing	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840		
New	184	368	552	736	920	1,104	1,288	1,472	1,656	1,840		
Total operations	2,024	2,208	2,392	2,576	2,760	2,944	3,128	3,312	3,496	3,680		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Existing	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$3.44	$25.8	$30.2
New	$0.34	$0.69	$1.03	$1.37	$1.72	$2.06	$2.40	$2.75	$3.09	$3.44	$12.8	$15.9
Total operations	$3.78	$4.12	$4.47	$4.81	$5.2	$5.5	$5.8	$6.2	$6.5	$6.9	$38.6	$46.0
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Existing	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99	$22.5	$26.3
New	$0.30	$0.60	$0.90	$1.20	$1.50	$1.79	$2.09	$2.39	$2.69	$2.99	$11.1	$13.8
Total operations	$3.29	$3.59	$3.89	$4.19	$4.49	$4.78	$5.08	$5.4	$5.7	$6.0	$33.6	$40.1

C. Royalty Provisions

Royalty payments are income to Federal or Tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important, but sometimes difficult, problem in cost estimation is to distinguish between real costs and transfer payments. While transfer payments should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.[66]

The rule specifies that gas flared when the operator's capture percentage is below the capture target is royalty-bearing.

The royalty provisions only apply to gas originating from the Federal and Tribal mineral estates, and not to gas originating from non-Federal and non-Indian mineral owners. Therefore, any incremental royalty resulting from this rule would be applied only to natural gas from Federal and Indian leases, and for the Federal and Indian portion of gas produced from leases with mixed owndership.

The royalty implications of this rule should be viewed in concert with the gas capture targets. We expect that operators will manage their portfolios such that they comply with the gas capture requirements and do not conduct excessive flaring.

In section 7A of this analysis, we examine the implications of the gas capture requirements assuming full compliance. Meaning, we examine how operators will respond to those requirements and avoid excessive flaring. Therefore, we do not examine the implications of the royalty provisions here, since that would result in a double-counting of impacts. However, if operators do not fully operate in compliance with the gas capture requirements, then the rule would result in additional royalty payments to Federal and Tribal governments.

7.7 Well Drilling, Completions, and Maintenance

A. Well Drilling

The rule operators to capture, flare, inject or use gas generated during drilling operations.. The operator is allowed to vent the drilling gas if each of the other options are technically infeasible. Operators already control gas from drilling operations as a general matter of safety and operating practice. As such, any costs associated with this requirement are expected to be *de minimis*.

B. Well Completions and Other Well Maintenance (Workovers)

The rule operators to capture, flare, inject or use gas generated during well completions of hydraulically fractured wells, and it deems an operator that is complying with the NSPS Subparts OOOO and OOOOa to be in compliance with the BLM requirements. Subparts OOOO or OOOOa apply to all new hydraulically fractured wells and refractured wells, we do not expect this

[66] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available on the web at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

rule to have an additional practical impact and no costs, benefits, or distributional impacts are associated with this requirement.

The final rule does not cover conventional well completions. According to the GHG Inventory, the emissions factors for these activities are very small. In addition, the drilling and completion of conventional wells are now relatively infrequent, with unconventional wells the norm.

7.8 Pneumatic Controllers

The final rule requires operators to replace exisiting high-bleed continuous pneumatic controllers with a controllers whith a bleed rate of 6 standard cubic feet per hour or less. NSPS Subpart OOOO has required that all continuous pneumatic controllers newly installed or modified since August 23, 2011, not be high bleed. . Also, Colorado requires operators to replace high bleed controllers, and Wyoming requires all controllers in the Upper Green River Basin (UGRB) to be low bleed by January 2017.

We estimated the number of impacted controllers by scaling down the EPA's nationwide estimate for the number of continuous high bleed pneumatic controllers (listed in the 2016 GHG Inventory, Annex 3) according to the share of oil and gas production (7.06% and 10.49%, respectively) coming from Federal and Indian lands in 2014. We then removed the potentially impacted controllers in the states of Colorado and Wyoming (Upper Green River Basin wells only).

The average capital cost of a low bleed pneumatic controller is estimated to be $2,594, or $369 per year when the capital costs are annualized with a 7% discount rate over a 10-year period and $304 per year when the capital costs are annualized with a 3% discount rate over a 10-year period (costs escalated to 2012 dollars).[67] A controller in either the petroleum production segment or natural gas production segment is expected to pay for itself on an annual basis over the life of the equipment when the proceeds from additional gas capture are considered.

Savings due to fuel sales were calculated using the differential of whole gas emission factors from high bleed (37.30 scfh) to low bleed (1.39 scfh) as indicated in EPA Subpart W for controllers in the natural gas production segment (40 CFR, Table W-1A), and the differential of whole gas emission factors from high bleed (17.46 scfh) to low bleed (2.75 scfh) as indicated in the 2015 GHG Inventory for controllers in the petroleum production segment.[68] Methane reductions were calculated using the conversion factors: 82.8% methane by volume of natural gas; and 1 Mcf of methane = 0.0208 ton of methane. VOC reductions were calculated using a conversion factor, 1 tpy VOC = 0.278 tpy methane.[69]

[67] Controller costs come from EPA (2011b), p. 5-15. Costs are escalated to 2012 dollars using the CE Indices for 2008 (575.4) and 2012 (584.6). The average controller cost is $2,594 with a range of $532-$8,994.
[68] We note that the CTG analysis assumes the same level of reductions for low bleed pneumatic control replacements in the natural gas and petroleum production sectors. We decided to make the distinction due to reported differences in the reference materials.
[69] Assumptions used in the CTG analysis; values drawn from an EPA 2011 Gas Composition Memorandum.

Requirements

Estimated annual impacts:

- Impact up to about 5,040 existing high-bleed pneumatic controllers;
- Costs of about $2 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $3 – 4 million per year;
- Monetized benefits of the reduced methane emissions of $19 – 25 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $20 – 27 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 1.05 Bcf per year;
- Reduce methane emissions by about 18,000 tons per year; and
- Reduce VOC emissions by about 65,000 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $12 – 14 million (NPV using a 7% discount rate) or $14 – 16 million (NPV using a 3% discount rate);
- Total cost savings of about $26 million (NPV using a 7% discount rate) or $31 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $165 million (NPV using a 7% discount rate) or $195 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $177 – 179 million (NPV using a 7% discount rate) or $209 – 212 million (NPV using a 3% discount rate).

Table 7-8: Estimated Impacts of Pneumatic Controller Requirements

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Impacted Pneumatic Controllers												
Existing controllers - petroleum sector	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890		
Existing controllers - natural gas sector	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150		
Total controllers	5,040	5,040	5,040	5,040	5,040	5,040	5,040	5,040	5,040	5,040		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Existing controllers - petroleum sector	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$1.07	$8.02	$9.37
Existing controllers - natural gas sector	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$0.79	$5.95	$6.96
Total controllers	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$1.86	$14.0	$16.3
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Existing controllers - petroleum sector	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$0.88	$6.61	$7.72
Existing controllers - natural gas sector	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$4.91	$5.73
Total controllers	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$11.5	$13.5
Estimated Costs - CO2 Emissions Additions (tons)												
Existing controllers - petroleum sector	14	14	14	14	14	14	14	14	14	14		
Existing controllers - natural gas sector	26	26	26	26	26	26	26	26	26	26		
Total controllers	40	40	40	40	40	40	40	40	40	40		
Value of CO2 Additions ($MM)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.01	$0.01
Estimated Benefits Cost Savings ($ in million)												
Existing controllers in the petroleum production sector	$0.89	$1.04	$1.16	$1.28	$1.25	$1.25	$1.37	$1.44	$1.48	$1.44	$9.22	$10.9
Existing controllers in the natural gas production sector	$1.62	$1.89	$2.10	$2.32	$2.27	$2.28	$2.48	$2.62	$2.68	$2.61	$16.7	$19.8
Total controllers	$2.51	$2.93	$3.26	$3.60	$3.51	$3.53	$3.85	$4.06	$4.16	$4.05	$25.9	$30.8
Estimated Benefits Incremental Production (Bcf)												
Existing controllers - petroleum sector	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37		
Existing controllers - natural gas sector	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68		
Total controllers	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05		
Estimated Methane Emissions Reductions (tons)												
Existing controllers - petroleum sector	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400		
Existing controllers - natural gas sector	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600		
Total CH4 reductions	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000		
Value of CH4 reductions ($MM)	$19.47	$19.47	$21.24	$21.24	$21.24	$23.01	$23.01	$24.78	$24.78	$24.78	$165	$195
Estimated VOC Emissions Reductions												
Existing controllers - petroleum sector	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100		
Existing controllers - natural gas sector	41,800	41,800	41,800	41,800	41,800	41,800	41,800	41,800	41,800	41,800		
Total VOC reductions	64,900	64,900	64,900	64,900	64,900	64,900	64,900	64,900	64,900	64,900		

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$20	$21	$23	$23	$23	$25	$25	$27	$27	$27	$177	$209
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$20	$21	$23	$23	$23	$25	$25	$27	$27	$27	$179	$212

7.9 Pneumatic Pumps

The final rule requires the operator to replace a pneumatic diaphragm pump with a zero-emissions pump or route the exhaust gas to capture. Alternatively, if the operator determines that replacing the pump with a zero-emissions pump is not viable because a pneumatic pump is necessary to perform the function, and routing to capture is technically infeasible or unduly costly, the operator may route the exhaust gas to an existing flare or combustor on site, or if there is no flare or combustor on site, the operator may take no further action. The final rule's requirements do not apply to pneumatic piston pumps or to pneumatic pumps that would be subject to NSPS OOOOa if they were a new, modified or reconstructed source.

Commenters asserted that the BLM's own data regarding gas recovery from piston pumps demonstrated that replacing chemical injection pumps is not cost effective. The BLM has further considered coverage of piston pumps and concluded that it does not make sense to require their replacement in this rule given their very small volumes of gas releases. However, some chemical injection pumps are diaphragm pumps rather than piston pumps, and the BLM notes that diaphragm pumps release much larger volumes of gas. Thus, the BLM has limited the provisions on pneumatic pumps to diaphragm pumps used for any purpose.

The NSPS Subpart OOOOa requires operators to control the emissions from new, modified and reconstructed pneumatic diaphragm pumps. Therefore, the BLM's requirements would apply only to pumps that were in use prior to the publication date of the Subpart OOOOa proposal. In addition, Wyoming will regulate pneumatic pumps in the UGRB (Upper Green River Basin) beginning in January 2017. Therefore, we removed these facilities from those impacted by the BLM's rule.

To determine the number of impacted existing pumps, we scaled down the EPA's nationwide estimate for the number of pneumatic pumps (listed in the 2016 GHG Inventory, Annex 3) according to the share of oil and gas production coming from Federal and Indian lands in 2014. We then reduced the number of impacted pumps by 3.29% and 17.46%, or the share of producing oil and gas wells in Wyoming's UGRB, respectively, since those pumps should already be in compliance with the BLM's rule by the time it would be effective. In addition, we made the assumption that half of the remaining pumps are diaphragm pumps (covered by the rule) and the other half are piston pumps (not covered by the rule). This 50/50 split was the same assumption that the EPA made in its analysis of the Subpart OOOOa rule (see TSD at p. 149).

The replacement of gas-assisted pumps may vary in cost and feasibility. We describe the costs and considerations presented in the EPA's CTG (pp. 7-7 – 7-16):

- <u>Converting to a solar powered pump:</u> Total capital cost of $2,227 (in 2012 dollars) and no special operating costs; meaning, a calculated annualized cost of $317 per year using a 7% discount rate. When replacing a diaphragm pump, the EPA estimates emissions reductions of 3.46 tpy of CH4 and 0.96 tpy of VOC and gas recovery of 197 Mcf/year per device.
- <u>Converting to an electric pump:</u> Total capital cost of $4,647 (in 2012 dollars) to replace a diaphragm pump with annual operating costs estimated to be $293. Therefore, the EPA calculates, using a 7% discount rate, annualized costs of $954 for a diaphragm pump and emissions reductions of 3.46 tpy of CH4 and 0.96 tpy of VOC and gas recovery of 197 Mcf/year per device.

- Converting to an instrument air system: The cost varies, depending on the size of the compressor, power supply, labor, and equipment. The total capital costs range from about \$6,000 - \$53,000 and operating costs range from about 9,000 - \$65,000. The estimated annualized costs, using a 7% discount rate and an equipment life of 10 years, ranges from about \$10,000 to \$72,000. When replacing a diaphragm pump, the EPA estimates emissions reductions of 3.46 tpy of CH_4 and 0.96 tpy of VOC and gas recovery of 197 Mcf/year per device.
- Routing emissions to an existing combustion device: Total cost of \$5,433 (in 2012 dollars); meaning, a calculated annualized cost of \$774 using a 7% discount rate. Since the gas is combusted, there is no gas savings; however, it would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump.
- Routing emissions to a new combustion device: Total capital cost of \$34,250 and annual operating costs of \$17,001 (in 2012 dollars); meaning, a calculated annualized cost of \$21,877 using a 7% discount rate. Since the gas is combusted, there is no gas savings; however, it would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump.
- Routing emissions to an existing vapor recovery unit (VRU): Total cost of \$5,433 (in 2012 dollars); meaning, a calculated annualized cost of \$774 using a 7% discount rate. When routing to a VRU from a diaphragm pump, the EPA estimates emissions reductions of 3.29 tpy of CH_4 and 0.91 tpy of VOC and gas recovery of 187 Mcf/year per device.
- Routing emissions to a new VRU: Total capital cost of \$104,000 and annual operating costs of \$9,932 (in 2012 dollars); meaning, a calculated annualized cost of \$24,755 using a 7% discount rate. When routing to a VRU from a diaphragm pump, the EPA estimates emissions reductions of 3.29 tpy of CH_4 and 0.91 tpy of VOC and gas recovery of 187 Mcf/year per device.

We estimate the engineering costs and emissions reductions for the pneumatic pump requirements using the following data points:

Metric	Value	Explanation
Percent of compliance through replacement pumps	50%	BLM assumption
Annualized cost of compliance through replacement pumps (\$/pump) (using 7% discount rate) (in 2012 dollars)	\$317	EPA's CTG presents costs using a 7% discount rate only, explaining that the difference in costs among the discount rates is minor.
Annualized cost of compliance through replacement pumps (\$/pump) (using 3% discount rate) (in 2012 dollars)	\$261	Calculated using the capital costs in the CTG and its assume 10 year life of equipment.
Methane emissions reductions with replacement pump (tpy/pump)	3.46	EPA's CTG
VOC emissions reductions with replacement pump (tpy/pump)	0.96	EPA's CTG
Gas savings for compliance through replacement pumps (Mcf/yr)	197	EPA's CTG
Percent of compliance through routing to existing combustion device	50%	BLM assumption
Annualized cost of compliance through existing combustion device (\$/pump) (using 7% discount rate) (in 2012 dollars)	\$774	EPA's CTG presents costs using a 7% discount rate only, explaining that the difference in costs among the discount

		rates is minor.
Annualized cost of compliance through existing combustion device ($/pump) (using 3% discount rate) (in 2012 dollars)	$637	Calculated using the capital costs in the CTG and its assume 10 year life of equipment.
Methane emissions reductions with replacement pump (tpy/pump)	3.29	EPA's CTG
VOC emissions reductions with replacement pump (tpy/pump)	0.91	EPA's CTG

Requirements

Estimated annual impacts:

- Impact up to about 7,950 existing diaphragm pumps;
- Costs of about $4 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $2 – 3 million per year;
- Monetized benefits of the reduced methane emissions of $29 – 37 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $26 – 36 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 0.78 Bcf per year;
- Reduce methane emissions by about 27,000 tons per year; and
- Reduce VOC emissions by about 7,000 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $27 – 33 million (NPV using a 7% discount rate) or $31 – 38 million (NPV using a 3% discount rate);
- Total cost savings of about $19 million (NPV using a 7% discount rate) or $23 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $245 million (NPV using a 7% discount rate) or $289 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $232 – 238 million (NPV using a 7% discount rate) or $274 – 281 million (NPV using a 3% discount rate).

While we estimate that the final rule would impact about 7,950 pneumatic pumps, it is also likely that a portion of these pumps would not be impacted by the rule at all, given that the final rule does not cover temporary pumps, those sites where there is no existing flare device on-site or routing to an existing flare device is technically infeasible, or if compliance would impose costs on the operator such that the operator would cease production and abandon significant oil reserves.

Table 7-9: Estimated Impacts of Pneumatic Pump Requirements

YEAR	Annual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Impacted Pneumatic Pumps												
Total pumps	7,954	7,954	7,954	7,954	7,954	7,954	7,954	7,954	7,954	7,954		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Total pumps	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$4.34	$32.6	$38.1
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Total pumps	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$3.57	$26.8	$31.4
Estimated Costs - CO2 Emissions Additions (tons)												
Total pumps	60	60	60	60	60	60	60	60	60	60		
Value of CO2 Additions ($MM)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.003	$0.003	$0.003	$0.003	$0.003	$0.02	$0.02
Estimated Benefits Cost Savings ($ in million)												
Total pumps	$1.87	$2.19	$2.43	$2.69	$2.62	$2.64	$2.88	$3.03	$3.11	$3.02	$19.4	$23.0
Estimated Benefits Incremental Production (Bcf)												
Total pumps	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78		
Estimated Methane Emissions Reductions (tons)												
Total CH4 reductions	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800		
Value of CH4 reductions ($MM)	$29.0	$29.0	$31.6	$31.6	$31.6	$34.2	$34.2	$36.9	$36.9	$36.9	$245	$289
Estimated VOC Emissions Reductions (tons)												
Total VOC reductions	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$26	$27	$30	$30	$30	$33	$33	$36	$36	$36	$232	$274
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$27	$28	$30	$31	$31	$33	$34	$36	$36	$36	$238	$281

7.10 Liquids Unloading

The rule requires operators to "minimize vented gas and the need for well venting associated with downhole well maintenance and liquids unloading, consistent with safe operations." For wells equipped with a plunger lift system and/or an automated well control system, minimizing gas venting includes optimizing the system to minimize gas losses to the extent possible consistent with removing liquids. For operators that intend to unload liquids by manual purging, the rule requires that prior to manually purging a well for the first time after the effective date of the rule, the operator must consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly. The operator must use specified best practices when manually purging a well, including staying on site during the event and keeping records, and must notify the BLM when the duration or volume of manual purging exceeds specified thresholds.

We estimate that there are about 8,500 operating gas wells where gas is vented during liquids unloading. Of those wells, we estimate that about 6,950 wells (or 82%) are equipped with plunger lifts, while 1,550 wells (or 18%) are not equipped with plunger lifts. The wells impacted by the best practices requirements would be those 1,550 wells that are not equipped with plunger lifts. In addition to those wells, there is the likelihood that some number of currently producing gas wells will develop liquids accumulation issues in the future, and depending on how the operator removes the liquids from the wellbore, those wells could potentially be impacted by the requirements.

We do not expect that these requirements will have much effect on operators' choice between installing equipment to remove liquids and manual purging. As indicated by the estimate that 82% of wells with venting during liquids unloading already have plunger lifts, many operators already find plunger lifts the most cost-effective way to unload liquids. Nor do we anticipate that the best practices requirement for manual purging will impose any significant additional burden on operators. First, we expect that a prudent operator will remain onsite for the duration of the liquids unloading activity to minimize the unnecessary loss of gas, even in the absence of the requirement. It is in the best interest of the operator to limit the venting of gas to only that amount which is necessary to remove liquids from the wellbore and return the well to production. Second, the available data show that average vent times are relatively short in duration, further supporting the idea that the operator would remain onsite. Data from Shires & Lev-on analysis of API/ANGA (American Petroleum Institute /America's Natural Gas Alliance) survey data, for wells in the Rocky Mountain region, indicate that the average vent times for wells equipped with plunger lifts and wells not equipped with plunger lifts were 0.93 and 1.89 hours per event, respectively. Allen et al. (2013) found, for wells in the Rocky Mountain region, that average vent times for wells not equipped with plunger lifts were 0.73 hours per event.

Nevertheless, we recognize that the requirement to determine the need for manual purging in the first instance and keep records on each manual purging event may tip the balance for some operators towards installing equipment to remove liquids. For purposes of this analysis, we estimate that roughly 25 gas wells per year might develop liquids loading problems and have plunger lifts installed, where the operators would not have installed plunger lifts absent this rule (See Table 7-10a). We developed these estimates assuming about 900 gas well completions per year in the future

on Federal and Indian lands[70] and a regional distribution of new wells consistent with the distribution of currently producing gas wells.[71] The estimated number of wells without plunger lifts, by region, are based on data from the 2015 GHG Inventory and 2016 GHG Inventory, Annex 3.

Table 7-10a: Estimated Existing Gas Wells Impacted by the Rule and Calculated Difference in Venting

NEMS REGION	Estimated number of existing wells that would be impacted	Gas venting without plunger lifts (Mcfy/well)	Gas venting with plunger lifts (Mcfy/well)	Difference (Mcfy/well)
Northeast	81	315	166	-149
Midcontinent	54	1380	230	-1150
Rocky Mountain	799	154	2578	2424
Southwest	565	4	97	93
West Coast	4	345	304	-41
Gulf Coast	44	70	301	231
Total	1,547		Weighted Average	1,244

Table 7-10b: Estimated Annual New Gas Wells Completions and Wells that Would Not Have Been Equipped with Plunger Lifts Absent This Rule

Region	Federal Lands		Indian Lands	
	Estimated gas well completions	Estimated wells that would develop liquids loading problems and not have used plunger lifts	Estimated gas well completions	Estimated wells that would develop liquids loading problems and not have used plunger lifts
Northeast	11	1	0	0
Midcontinent	14	1	6	0
Rocky Mtn	722	11	93	1
Southwest	44	9	0	0
West Coast	1	0	0	0
Gulf Coast	10	1	0	0
Total	801	**22**	**99**	**2**

[70] Or that about 30% of future well completions, numbering 3,000 per year, would be on gas wells. These assumptions are consistent with recent trends in completions on Federal and Indian lands.
[71] As of January 1, 2015.

Since the gas wells that encounter liquids accumulation problems generally do so after the well starts going into decline, the timing of any future impacts of this rule is also uncertain. It seems reasonable to conclude that the potentially impacted new wells would develop liquids loading problems many years after the effective date of the rule.

The EPA's Gas Star Program has shown that interventions taken (where plunger lift or other) at the start of a well's decline have been more successful than interventions taken at a later time. The cost of various alternatives uncontrolled liquids unloading are shown in Table 7-10c (in 2012 dollars), but these costs do not include the sale of recovered gas nor the benefits to well productivity. The annualized cost of a plunger lift is estimated to be $1,845 - $2,816 using a 7% discount rate. The annualized cost of a "smart" (or automated) plunger lift is estimated to be $2,471 - $4,520 using a 7% discount rate. Both estimates are based on an equipment life of 10 years.

The costs presented in the table do not include sales from the recovered gas. The Gas STAR Program information indicates that operators installing plunger lifts may experience increases in production from two effects – gas that was vented is now captured and the well's production decline may slow improving productivity. The gains are well specific but it was the experience of the Gas Star partners that the sales of gas from these two effects paid for the plunger lift.

Overall, as was demonstrated by the experiences of the Gas STAR Program partners, we would expect that the boost in well productivity and the sale of recovered gas would pay for the capital costs of the production equipment and installation

Table 7-10c: Annualized Cost of Methods to Unload Liquids

Cost Category	Plunger Lift	"Smart" Plunger Lift	Traditional Beam Lift	Remedial Treatment
Capital and Startup Costs (2012)	$2,274 - $9,094	$6,670 - $21,062	$30,315 - $60,628	$0
Maintenance (2012)($/yr)	$1,521	$1,521	$1,521 - $22,818	$0
Well Treatment (2012)	$0	$0	$15,446+	$15,446+
Electrical (2012)($/yr)	$0	$0	$1,170 - $8,542	$0
Salvage (2012)	$0	$0	($14,042 - $48,561)	$0
Annualized costs (using 3% interest, 10 year equipment life)	$1,788 - 2,587	$2,303 - $3,990	$6,410 - $34,585	$1,811
Annualized costs (using 7% interest, 10 year equipment life)	$1,845 - $2,816	$2,471 - $4,520	$7,207 - $35,277	$2,199

Source: Plunger lift, traditional beam lift, and remedial treatment cost data come from EPA (2006), p. 7. Smart plunger lift cost data come from EPA (2011b), p.11, except for maintenance costs which are assumed to be the same as for a plunger lift. Costs are escalated to 2012 dollars using the CE Indices for 2006 (499.6), 2011 (585.7), and 2012 (584.6). Remedial treatment includes soaping, swabbing, and blowing down. For traditional beam lift, maintenance costs include workovers and assume 1 to 15 workovers per year. The table does not include savings due to fuel sales, although these are possible with with plunger lifts, smart plunger lifts, and beam lifts.

For the purposes of this analysis, we estimate impacts of the liquids unloading requirements, assuming that operators would install smart or automated plunger lifts on the impacted wells, since plunger lifts appear to be the most effective and widely-used method of liquids removal. Our assumptions for this analysis are as follows:

- Impacted wells include 1,550 existing wells and 25 new wells per year;
- Plunger lift costs of about $3,500 (capital costs annualized using a 7% discount rate) or $3,150 (capital costs annualized using a 3% discount rate). These amounts are generally the midpoints of the cost ranges for smart plunger lifts listed in the above table;
- Gas savings of 1,244 Mcf per year per well. This volume is the weighted average of the differences in gas venting for wells not equipped with lifts and wells equipped with lifts estimated to be on Federal and Indian lands, by region. The emissions data, by region, come from the GHG Inventory, Annex 3.
- Methane reductions were calculated using the conversion factors: 82.8% methane by volume of natural gas; and 1 Mcf of methane = 0.0208 tons of methane.
- VOC reductions were calculated using a conversion factor, 1 tpy VOC = 0.278 tpy methane.

Estimated annual impacts:

- Impact up to about 1,550 existing wells and about 25 new wells per year;
- Costs of about $6 million per year (capital costs annualized using a 7% discount rate) or $5 – 6 million per year (capital costs annualized using a 3% discount rate);
- Cost savings of about $5 – 9 million per year;
- Monetized benefits of the reduced methane emissions of $36 – 53 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $36 – 56 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by roughly 2 Bcf per year;
- Reduce methane emissions by 34,000 – 39,000 tons per year; and
- Reduce VOC emissions by about 121,000 – 138,000 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $40 – 44 million (NPV using a 7% discount rate) or $47 – 52 million (NPV using a 3% discount rate);
- Total cost savings of about $52 million (NPV using a 7% discount rate) or $62 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $329 million (NPV using a 7% discount rate) or $390 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $336 – 341 million (NPV using a 7% discount rate) or $400 – 405 million (NPV using a 3% discount rate).

The estimates provided likely overestimate the impacts of the rule, because the liquids unloading requirements do not require the operator to install a plunger lift. Also, since the use of plunger lifts is reportedly common among operators, it is possible that operators have already installed lift systems on wells where the installations are feasible and that the remaining wells are those where

such installations are infeasible. Accordingly, the operators might not install any additional plunger lifts or realize the amount of gas savings assumed in conducting this analysis.

Table 7-10c: Estimated Impacts of Liquids Unloading Requirements

YEAR	Annual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Impacted Wells with Liquids Unloading												
Existing wells	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550		
New wells	25	50	75	100	125	150	175	200	225	250		
Total wells	1,575	1,600	1,625	1,650	1,675	1,700	1,725	1,750	1,775	1,800		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Existing wells	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$5.43	$40.8	$47.7
New wells	$0.09	$0.18	$0.26	$0.35	$0.44	$0.53	$0.61	$0.70	$0.79	$0.88	$3.25	$4.04
Total wells	$5.51	$5.60	$5.69	$5.78	$5.86	$5.95	$6.04	$6.13	$6.21	$6.30	$44.0	$51.7
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Existing wells	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$4.88	$36.7	$42.9
New wells	$0.08	$0.16	$0.24	$0.32	$0.39	$0.47	$0.55	$0.63	$0.71	$0.79	$2.93	$3.64
Total wells	$4.96	$5.04	$5.12	$5.20	$5.28	$5.36	$5.43	$5.51	$5.59	$5.67	$39.6	$46.5
Estimated Costs - CO2 Emissions Additions (tons)												
Existing wells	73	73	73	73	73	73	73	73	73	73		
New wells	1	2	4	5	6	7	8	9	11	12		
Total wells	74	76	77	78	79	80	82	83	84	85		
Value of CO2 Additions ($MM)	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004	$0.004	$0.02	$0.03
Estimated Benefits Cost Savings ($ in million)												
Existing controllers in the petroleum production sector	$4.61	$5.40	$5.99	$6.62	$6.46	$6.49	$7.08	$7.46	$7.65	$7.44	$47.7	$56.6
Existing controllers in the natural gas production sector	$0.07	$0.17	$0.29	$0.43	$0.52	$0.63	$0.80	$0.96	$1.11	$1.20	$4.11	$5.16
Total controllers	$4.68	$5.57	$6.28	$7.04	$6.98	$7.12	$7.88	$8.42	$8.76	$8.64	$51.8	$61.8
Estimated Benefits Incremental Production (Bcf)												
Existing wells	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93		
New wells	0.03	0.06	0.09	0.12	0.16	0.19	0.22	0.25	0.28	0.31		
Total wells	1.96	1.99	2.02	2.05	2.08	2.11	2.15	2.18	2.21	2.24		
Estimated Methane Emissions Reductions (tons)												
Existing wells	33,200	33,200	33,200	33,200	33,200	33,200	33,200	33,200	33,200	33,200		
New wells	500	1,100	1,600	2,100	2,700	3,200	3,700	4,300	4,800	5,400		
Total CH4 reductions	33,700	34,300	34,800	35,400	35,900	36,400	37,000	37,500	38,000	38,600		
Value of CH4 reductions ($MM)	$36.4	$37.0	$41.0	$41.6	$42.2	$46.4	$47.1	$51.5	$52.2	$52.9	$329	$390
Estimated VOC Emissions Reductions												
Existing wells	119,000	119,000	119,000	119,000	119,000	119,000	119,000	119,000	119,000	119,000		
New wells	2,000	4,000	6,000	8,000	10,000	12,000	13,000	15,000	17,000	19,000		
Total VOC reductions	121,000	123,000	125,000	127,000	129,000	131,000	132,000	134,000	136,000	138,000		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$36	$37	$42	$43	$43	$48	$49	$54	$55	$55	$336	$400
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$36	$38	$42	$43	$44	$48	$50	$54	$55	$56	$341	$405

7.11 Storage Vessels

The rule requires operators either to capture or combust releases from storage vessels with the potential to emit at or above 6 tpy of VOC per vessel (with exceptions to this requirement). We estimate that this would impact 292 storage tanks on Federal and Indian lands.

The EPA's NSPS currently regulates new, modified or reconstructed storage vessels above a 6 tpy of VOC threshold, and the rule would not affect those vessels. Similarly, Colorado regulates new and existing storage tanks above a 6 tpy of VOC threshold, Utah requires the control of tank emissions, and Wyoming regulates new and existing storage tanks in the UGRB beginning in January 2017. As a practical matter, the rule would not require any additional controls on storage vessels in these jurisdictions. In analyzing the impact of the requirements for storage vessels, we used data from the EPA's analysis for the NSPS Subpart OOOO, which considered existing operator activity to comply with state requirements. Although it appear unlikely that the EPA's analysis accounted for Wyoming's regulations concerning the UGRB, we did not remove any additional facilities from this impacts analysis since the number of impacted facilities is already very low.

For cost data, we used data from EPA's analysis supporting the Control Techniques Guidelines for the Oil and Natural Gas Industry, which evaluates controls on existing sources. During the public comment period for the proposed rule, we received comments stating that some existing storage tanks would need to be retrofitted or replaced in order to handle increased pressures driven by the connection to a VRU or combustor. The CTG analysis includes these retrofit costs.

In addition, we received comment that the RIA for the proposed rule underestimated the number of tanks that would be subject to the requirements. In light of the comments, the BLM has clarified that in cases in which multiple storage tanks comprise a tank battery, the VOC threshold applies to the average VOC emissions of each tank within the battery.

We estimated the number of impacted tanks using a similar methodology as used in the EPA's Regulatory Impact Analysis for the NSPS Subpart OOOO. In its analysis, the EPA analyzed a sample of tanks for production volumes and emissions. It categorized each into model tank batteries (some of the data from the EPA's Background Supplemental Technical Support Document for the NSPS is in Table 7-11a). We determined the number of crude oil vessels on Federal and Indian lands as of January 1, 2014 (or the end of 2013), assuming that each well site has one storage vessel. We determined the number of condensate storage vessels on Federal and Indian Lands by multiplying the number of nationwide storage tanks, as indicated by the EPA's Background Supplemental Technical Support Document, by 12%. According to EIA data and BLM's AFMSS data, gas wells on Federal and Indian lands account for about 12% of the nationwide onshore gas wells.

Of that tank population, we determined the number of uncontrolled storage vessels using the EPA's assumption in its Background Supplemental Technical Support Document that 36% of storage vessels (irrespective of model category) would be uncontrolled without the NSPS regulation. We also used the EPA's data for uncontrolled VOC emissions per storage vessel within each model tank battery. See Table 7-11b

Table 7-11a: Baseline Activity Data for Crude Oil and Condensate Storage Vessels

Parameter	Model Crude Oil Tank Batteries			
	A	B	C	D
Percent of vessels in model size range[1]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[2]	30,765	1,283	256	179
Percent of throughput across tank batteries[1]	26%	7%	15%	51%
Crude oil throughput per storage vessel (bbl/day)[1]	1.96	13.0	130	652
Parameter	**Model Condensate Tank Batteries**			
	E	**F**	**G**	**H**
Percent of vessels in model size range[1]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[3]	6,729	280	56	39
Percent of throughput across tank batteries[1]	26%	7%	15%	51%
Condensate throughput per storage vessel (bbl/day)[1]	1.6	10.7	106.8	534

[1] EPA (2012). Background Supplemental Technical Support Document for the Final New Source Performance Standards, p. 7-2.
[2] Assumes one storage vessel per well site. Calculated by multiplying the number of producing oil wells on Federal and Indian lands on January 1, 2014 by the percent of the number of vessels in the model size range.
[3] Assumes that about 12% of the condensate storage vessels identified by the EPA in its Background Technical Support Document are on Federal and Indian Lands. We derived the 12% figure by dividing the the number of producing gas wells on Federal and Indian lands on January 1, 2014 (or 58,226 wells) by the number of gas wellsnationwide (less Gulf of Mexico wells) in 2013 (or 485,886 wells) as reported by the EIA (data are available at http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm).

Table 7-11b: Uncontrolled Crude Oil and Condensate Storage Vessels, and Uncontrolled Emissions

Parameter	Model Crude Oil Tank Batteries				
	A	B	C	D	Total
Total number of existing storage vessels	30,765	1,283	256	179	32,484
Number of uncontrolled storage vessels in absence of the rule[1]	11,075	462	92	65	11,694
Uncontrolled VOC emissions from storage vessel at model tank battery (tpy)[2]	0.4	2.8	28	140	171
Total uncontrolled VOC emissions (tpy)	4,430	1,294	2,584	9,038	17,346
Parameter	**Model Condensate Tank Batteries**				
	E	**F**	**G**	**H**	**Total**
Total number of existing storage vessels	6,729	280	56	39	7,105
Number of uncontrolled storage vessels in absence of the rule[1]	2,422	101	20	14	2,558
Uncontrolled VOC emissions from storage vessel at model tank battery (tpy)[2]	3.35	22.3	223	1,117	1,366
Total uncontrolled VOC emissions (tpy)	8,115	2,251	4,502	15,806	30,674

[1] Based on the assumption that 36% of vessels are uncontrolled. This assumption was used in the Background Supplemental Technical Support Document for the Final New Source Performance Standards, p. 7-2.
[2] EPA (2012). Background Supplemental Technical Support Document for the Final New Source Performance Standards, p. 7-2.

Regarding compliance for the affected tanks, the rule requires that with some exceptions, the operator either capture or combust the gas vapors coming from an affected tank. An operator may capture and produce the vapors using a VRU or combust the vapors using a combustor. We believe that when selecting from the compliance options, the operator will consider the availability of equipment, operational feasibility of the control method on the production site, and the availability of infrastructure to produce the gas that would be captured by a VRU. Engineering costs for each option are presented on an annualized basis in Table 7-11c and Table 7-11d.

In cases where the operator choses a combustor, there will be no additional resource recovery to help offset the engineering costs. In cases where the operator installs a VRU to capture the gas, we would expect the additional resource recovery to help offset the engineering costs. For this analysis, we assume that a VRU would return about 296 Mcf per year in additional production (derived from EPA reported annual cost savings of about $1,183 per year at $4 per Mcf). For its analysis of the NSPS Subpart OOOO tank requirements, the EPA assumed that half of the affected facilities would comply by installing a VRU and half would comply by installing a combustor. We used the same assumption in this analysis.

We estimated the potential methane and VOC emissions for the final rule threshold and alternative thresholds, above which a tank would be subject to the control requirements. The reductions were calculated as 95% of the uncontrolled emissions (shown in Table 7-11b).

Table 7-11c: EPA Costs for a Combustor on an Existing Source (Available in CTG at pp. 4-14 – 4-15)

Cost Item[a]	Cost ($2012)
Capital Cost Items	
Combustor[a]	$18,169
Freight and Design[a]	$1,648
Auto Ignitor[a]	$1,648
Surveillance System[b,c,d]	$3,805
Combustor Installation[a]	$6,980
Storage Vessel Retrofit[e]	$68,736
Total Capital Investment	$100,986
Annual Cost Items	
Operating Labor[f]	$5,155
Maintenance Labor[f]	$4,160
Non-Labor Maintenance[a]	$2,197
Pilot Fuel	$1,537
Data Management[c]	$1,057
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$11,088
Total Annual Cost ($/yr)	$25,194

a. Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
b. Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
c. U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards.* April 2012. EPA Docket ID No.EPA-HQ-OAR-2010-0505-4550.
d. Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent)(which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (http://research.stlouisfed.org/fred2/series/GDPDEF/#).
e. Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).
f. Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are $32.00/hr (for technical and maintenance labor) and $51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

Table 7-11d: EPA Costs for a VRU on an Existing Source (Available in CTG at p. 4-10)

Cost Item[a]	Cost ($2012)
Capital Cost Items	
VRU[a]	$90,000
Freight and Design[a]	$1,648
VRU Installation[a]	$11,154
Storage Vessel Retrofit[b]	$68,736
Total Capital Investment	$171,538
Annual Cost Items	
Maintenance	$9,396
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$18,834
Total Annual Costs w/o Savings ($/yr)	***$28,230***

[a.] Cost data from Initial Economic Impact Analysis (EIA) for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b.] Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, Installing Vapor Recovery Units on Storage Tanks, October 2006.

For the analysis of compliance costs, we assumed that operators would meet the requirements by using half combustors and half VRUs. Using a 7% discount rate to annualize the capital investment, we assumed per-unit annualized cost of $26,712 (average of $28,230 for a VRU and $25,194 for a combustor). Using a 3% discount rate to annualize the capital investment, we assumed per-unit annualized cost of $23,165 (average of $23,765 for a VRU and $22,565 for a combustor).

In addition to the threshold in the rule of 6 tons per year VOCs, we analyzed two alternative thresholds – 3 tons per year VOCs and 30 tons per year VOCs. While industry commenters recommended increasing the threshold to 10-15 tons per year of VOCs, the BLM did not have data allowing analysis of this alternative. The EPA analysis did include data for a 30 tons per year VOC threshold, so we analyzed that threshold. We can extrapolate that the costs and benefits of a 10-15 ton per year threshold would fall somewhere between the results of the 6 ton per year VOC threshold and the 30 ton per year VOC threshold. A summary of the estimated impacts of the requirements and the alternatives considered are shown in Table 7-11g and with more detail in Tables 7-11h-j.

Tank Requirements – 6 tpy VOC Threshold

Estimated annual impacts:

- Impact about 300 existing storage tanks;
- Costs of about $7 – 8 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $0.1 – 0.2 million per year;
- Monetized benefits of the reduced methane emissions of $8 – 10 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $0 – 3 million per year in 2017 – 2026 (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 0.04 Bcf per year;
- Reduce methane emissions by 7,100 tons per year; and
- Reduce VOC emissions by 32,500 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $51 – 59 million (NPV using a 7% discount rate) or $60 – 69 million (NPV using a 3% discount rate);
- Total cost savings of about $1 million (NPV using 7% and 3% discount rates);
- Total monetized social benefit from the reduction of methane emissions of $65 million (NPV using a 7% discount rate) or $77 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $7 – 15 million (NPV using a 7% discount rate) or $9 – 18 million (NPV using a 3% discount rate).

Alternative Tank Requirements – 3 tpy VOC Threshold

We estimate the following impacts for the alternative tank requirement (3 tpy VOC threshold).

Estimated annual impacts:

- Impact about 3,200 existing storage tanks;
- Costs of about $74 – 85 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of about $1 – 2 million per year;
- Monetized benefits of the reduced methane emissions of $10 – 12 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net costs of $71 – 74 million per year (capital costs annualized using a 7% discount rate) or $59 – 63 million per year (capital costs annualized using a 3% discount rate);
- Increase gas production by 0.5 Bcf per year;
- Reduce methane emissions by 9,100 tons per year; and
- Reduce VOC emissions by 41,400 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $553 – 638 million (NPV using a 7% discount rate) or $647 – 746 million (NPV using a 3% discount rate);
- Total cost savings of about $12 million (NPV using a 7% discount rate) or $14 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $83 million (NPV using a 7% discount rate) or $98 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net costs ranging from $459 – 543 million (NPV using a 7% discount rate) or $535 – 634 million (NPV using a 3% discount rate).

<u>Alternative Tank Requirements – 30 tpy VOC Threshold</u>

We estimate the following impacts for the alternative tank requirement (30 tpy VOC threshold).

Estimated annual impacts:

- Impact about 100 existing storage tanks;
- Costs of about $2 – 3 million per year (capital costs annualized using 7% and 3% discount rates);
- Cost savings of up to $0.06 million per year;
- Monetized benefits of the reduced methane emissions of $7 – 8 million per year in 2017 – 2026 (using the model average at the 3% discount rate);
- Net benefits of $4 – 6 million per year (capital costs annualized using 7% and 3% discount rates);
- Increase gas production by 0.01 Bcf per year;
- Reduce methane emissions by 6,100 tons per year; and
- Reduce VOC emissions by 27,900 tons per year.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $17 – 20 million (NPV using a 7% discount rate) or $20 – 23 million (NPV using a 3% discount rate);
- Total cost savings of about $0.4 million (NPV using 7% and 3% discount rates);
- Total monetized social benefit from the reduction of methane emissions of $56 million (NPV using a 7% discount rate) or $66 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net costs ranging from $36 – 39 million (NPV using a 7% discount rate) or $43 – 46 million (NPV using a 3% discount rate).

<u>Comparison of Storage Vessel Threshold and Alternatives</u>

The results of this analysis, illustrated in Table 7-11g below, show that among the alternatives examined, both the VOC thresholds of 6 tpy and 30 tpy produce net benefits, and the VOC threshold of 30 tpy has somewhat higher net benefits compared to the VOC threshold of 6 tpy. The BLM selected the threshold of 6 tpy in the final rule rather than 10, 15 or 30 tpy VOC in large

part because this threshold is consistent with the Colorado standards for new and existing storage vessels and the EPA OOOO standards for new, modified and reconstructed storage vessels, as well as being less stringent than the Wyoming standards for new and existing storage vessels in the Upper Green River Basin. In addition, the BLM notes that this threshold is exceeded only by the storage vessels with among the highest volumes of releases, and it covers only a very small number of storage vessels compared to the overall inventory. This suggests that this requirement, even with the 6 tpy threshold, is tightly targeted on storage vessels that are outliers in terms of their volumes of lost gas, which supports the BLM's conclusion that gas losses above the 6 tpy VOC threshold is unreasonable and wasteful.

Table 7-11g: Summary of Annual Impacts for Storage Tank Options

Metric	VOC Threshold		
	3 tpy	6 tpy (Final)	30 tpy
Annual Impacts			
Impacted tanks	3,176	292	99
Annual Costs – Engineering Costs ($ in million)	$74 – 85	$7 – 8	$2 – 3
Annual Benefits – Cost Savings ($ in million)	$1 – 2	$0.1 – 0.2	$0.03 – 0.06
Methane Reductions (tons)	9,100	7,100	6,100
Value of Methane Reductions ($ in million)	$10 – 12	$8 – 10	$7 – 8
Incremental Production (Bcf)	0.5	0.04	0.01
VOC Reductions (tons)	41,400	32,500	27,900
Annual Net Benefits ($ in million)	($59 – 74)	$0 – 3	$4 – 6

Table 7-11h: Impacts of a the Requirement to Control Storage Tanks Exceeding 6 tpy of VOC

	Annual										2017-2026	
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Impacted tanks												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	92	92	92	92	92	92	92	92	92	92		
Crude - model D	65	65	65	65	65	65	65	65	65	65		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	101	101	101	101	101	101	101	101	101	101		
Condensate - model G	20	20	20	20	20	20	20	20	20	20		
Condensate - model H	14	14	14	14	14	14	14	14	14	14		
Total tanks	292	292	292	292	292	292	292	292	292	292		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$18.5	$21.7
Crude - model D	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$13.0	$15.2
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$20.3	$23.7
Condensate - model G	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$4.05	$4.74
Condensate - model H	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$2.84	$3.32
Total costs	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$7.80	$58.6	$68.6
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$16.1	$18.8
Crude - model D	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$11.2	$13.1
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$17.6	$20.5
Condensate - model G	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$3.51	$4.11
Condensate - model H	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$2.46	$2.88
Total costs	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$50.9	$59.5
Estimated Costs - CO2 Emissions Additions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	1	1	1	1	1	1	1	1	1	1		
Crude - model D	1	1	1	1	1	1	1	1	1	1		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	1	1	1	1	1	1	1	1	1	1		
Condensate - model G	0	0	0	0	0	0	0	0	0	0		
Condensate - model H	0	0	0	0	0	0	0	0	0	0		
Total CO2 Additions	3	3	3	3	3	3	3	3	3	3		
Value of CO2 Additions ($MM)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001
Estimated Benefits Cost Savings ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.03	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.34	$0.40
Crude - model D	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.24	$0.28

YEAR	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.37	$0.44
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.09
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.06
Total cost savings	$0.10	$0.12	$0.13	$0.15	$0.14	$0.15	$0.16	$0.17	$0.17	$0.17	$1.07	$1.27
Estimated Benefits Incremental Production (Bcf)												
Crude - model B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Crude - model C	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model F	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Total incremental production	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04		
Estimated Benefits - Methane Emissions Reductions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	500	500	500	500	500	500	500	500	500	500		
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	500	500	500	500	500	500	500	500	500	500		
Condensate - model G	900	900	900	900	900	900	900	900	900	900		
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300		
Total CH4 reductions	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100		
Value of CH4 reductions ($MM)	$7.67	$7.67	$8.37	$8.37	$8.37	$9.06	$9.06	$9.76	$9.76	$9.76	$64.9	$76.6
Estimated VOC Emissions Reductions												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500		
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100		
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300		
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
Total VOC reductions	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$0	$0	$1	$1	$1	$1	$1	$2	$2	$2	$7	$9
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$1	$1	$2	$2	$2	$2	$2	$3	$3	$3	$15	$18

Table 7-11i: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 3 tpy of VOC

	Annual										2017-2026	
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Impacted tanks												
Crude - model B	462	462	462	462	462	462	462	462	462	462		
Crude - model C	92	92	92	92	92	92	92	92	92	92		
Crude - model D	65	65	65	65	65	65	65	65	65	65		
Condensate - model E	2,422	2,422	2,422	2,422	2,422	2,422	2,422	2,422	2,422	2,422		
Condensate - model F	101	101	101	101	101	101	101	101	101	101		
Condensate - model G	20	20	20	20	20	20	20	20	20	20		
Condensate - model H	14	14	14	14	14	14	14	14	14	14		
Total tanks	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Crude - model B	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$12.3	$92.7	$108
Crude - model C	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$18.5	$21.7
Crude - model D	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$13.0	$15.2
Condensate - model E	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$64.7	$486	$569
Condensate - model F	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$2.70	$20.3	$23.7
Condensate - model G	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$4.05	$4.74
Condensate - model H	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$2.84	$3.32
Total costs	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$84.8	$638	$746
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Crude - model B	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$10.7	$80.4	$94.0
Crude - model C	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$2.14	$16.1	$18.8
Crude - model D	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$11.2	$13.1
Condensate - model E	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$56.1	$422	$493
Condensate - model F	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$2.34	$17.6	$20.5
Condensate - model G	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$3.51	$4.11
Condensate - model H	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$2.46	$2.88
Total costs	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$73.6	$553	$647
Estimated Costs - CO2 Emissions Additions (tons)												
Crude - model B	5	5	5	5	5	5	5	5	5	5		
Crude - model C	1	1	1	1	1	1	1	1	1	1		
Crude - model D	1	1	1	1	1	1	1	1	1	1		
Condensate - model E	27	27	27	27	27	27	27	27	27	27		
Condensate - model F	1	1	1	1	1	1	1	1	1	1		
Condensate - model G	0	0	0	0	0	0	0	0	0	0		
Condensate - model H	0	0	0	0	0	0	0	0	0	0		
Total CO2 Additions	36	36	36	36	36	36	36	36	36	36		
Value of CO2 Additions ($MM)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.002	$0.002	$0.002	$0.002	$0.002	$0.011	$0.013
Estimated Benefits Cost Savings ($ in million)												
Crude - model B	$0.16	$0.19	$0.21	$0.23	$0.23	$0.23	$0.25	$0.26	$0.27	$0.26	$1.69	$2.01
Crude - model C	$0.03	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.34	$0.40

YEAR	Annual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026 NPV 7	NPV 3
Crude - model D	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.24	$0.28
Condensate - model E	$0.86	$1.00	$1.11	$1.23	$1.20	$1.21	$1.32	$1.39	$1.42	$1.38	$8.87	$10.5
Condensate - model F	$0.04	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.37	$0.44
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.09
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.06
Total cost savings	$1.12	$1.32	$1.46	$1.61	$1.57	$1.58	$1.73	$1.82	$1.86	$1.81	$11.6	$13.8
Estimated Benefits Incremental Production (Bcf)												
Crude - model B	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07		
Crude - model C	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model E	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36		
Condensate - model F	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Total incremental production	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47		
Estimated Benefits - Methane Emissions Reductions (tons)												
Crude - model B	300	300	300	300	300	300	300	300	300	300		
Crude - model C	500	500	500	500	500	500	500	500	500	500		
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900		
Condensate - model E	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700		
Condensate - model F	500	500	500	500	500	500	500	500	500	500		
Condensate - model G	900	900	900	900	900	900	900	900	900	900		
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300		
Total CH4 reductions	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100	9,100		
Value of CH4 reductions ($MM)	$9.78	$9.78	$10.7	$10.7	$10.7	$11.6	$11.6	$12.4	$12.4	$12.4	$82.8	$97.7
Estimated VOC Emissions Reductions												
Crude - model B	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200		
Crude - model C	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500		
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600		
Condensate - model E	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700	7,700		
Condensate - model F	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100		
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300		
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
Total VOC reductions	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400	41,400		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	-$74	-$74	-$73	-$73	-$73	-$72	-$72	-$71	-$71	-$71	-$543	-$634
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	-$63	-$62	-$61	-$61	-$61	-$60	-$60	-$59	-$59	-$59	-$459	-$535

Table 7-11j: Impacts of a the Alternative Requirement to Control Storage Tanks Exceeding 30 tpy of VOC

	Annual										2017-2026	
YEAR	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Impacted tanks												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	65	65	65	65	65	65	65	65	65	65		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	20	20	20	20	20	20	20	20	20	20		
Condensate - model H	14	14	14	14	14	14	14	14	14	14		
Total tanks	99	99	99	99	99	99	99	99	99	99		
Estimated Costs - Capital Costs Annualized Using a 7% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model D	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$13.0	$15.2
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model G	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$0.54	$4.05	$4.74
Condensate - model H	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$0.38	$2.84	$3.32
Total costs	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$2.64	$19.9	$23.2
Estimated Costs - Capital Costs Annualized Using a 3% Discount Rate ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model D	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$11.2	$13.1
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model G	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$3.51	$4.11
Condensate - model H	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$2.46	$2.88
Total costs	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$2.29	$17.2	$20.1
Estimated Costs - CO2 Emissions Additions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	1	1	1	1	1	1	1	1	1	1		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	0	0	0	0	0	0	0	0	0	0		
Condensate - model H	0	0	0	0	0	0	0	0	0	0		
Total CO2 Additions	1	1	1	1	1	1	1	1	1	1		
Value of CO2 Additions ($MM)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Estimated Benefits Cost Savings ($ in million)												
Crude - model B	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Crude - model C	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

YEAR	Annual										2017-2026	
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Crude - model D	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.24	$0.28
Condensate - model E	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model F	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Condensate - model G	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.09
Condensate - model H	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.06
Total cost savings	$0.03	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.06	$0.06	$0.06	$0.36	$0.43
Estimated Benefits Incremental Production (Bcf)												
Crude - model B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Crude - model C	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Crude - model D	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Condensate - model E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model F	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model G	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Condensate - model H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Total incremental production	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01		
Estimated Benefits - Methane Emissions Reductions (tons)												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	900	900	900	900	900	900	900	900	900	900		
Condensate - model H	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300		
Total CH4 reductions	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100		
Value of CH4 reductions ($MM)	$6.59	$6.59	$7.18	$7.18	$7.18	$7.78	$7.78	$8.38	$8.38	$8.38	$55.7	$65.8
Estimated VOC Emissions Reductions												
Crude - model B	0	0	0	0	0	0	0	0	0	0		
Crude - model C	0	0	0	0	0	0	0	0	0	0		
Crude - model D	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600		
Condensate - model E	0	0	0	0	0	0	0	0	0	0		
Condensate - model F	0	0	0	0	0	0	0	0	0	0		
Condensate - model G	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300	4,300		
Condensate - model H	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000		
Total VOC reductions	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900	27,900		
Net Benefits												
Net Benefits (Capital Costs Annualized at 7%) ($ MM)	$4	$4	$5	$5	$5	$5	$5	$6	$6	$6	$36	$43
Net Benefits (Capital Costs Annualized at 3%) ($ MM)	$4	$4	$5	$5	$5	$6	$6	$6	$6	$6	$39	$46

7.12 Leak Detection and Repair

Sections 3179.301 through 3179.305 require operators to inspect sites and equipment handling gas from a Federal or Indian lease, unit or communitized area, and sites and equipment handling produced water located on a Federal or Indian lease, except that sites containing only wellheads and no other equipment are exempt from these requirements. Operators must inspect using optical gas imaging (OGI) (such as an infra-red camera), a portable analyzer device, assisted by audio, visual, and olfactory (AVO) inspection, or another instrument-based monitoring device or method approved by the BLM. The operator must make the first inspection within one year of the effective date of the rule, and continue with semi-annual inspections (or quarterly for compressor stations), and must fix identified leaks within 30 days, unless there is good cause for a longer period.

Costs of Inspections

To meet these requirements, the operator is likely either to contract with a service provider to conduct the inspections or to conduct the inspections itself. Carbon Limits provides the following estimates of the costs of using a service provider, not including the costs to repair potential leaks or the cost savings from the gas recovered after leaks are repaired:[72]

- $400 per well site;
- $600 per single well batteries;
- $1,200 per multi-well batteries; and
- $2,300 per compressor station.

The Carbon Limits estimates are likely conservative. Rebellion Photonics indicates that its turn-key services are available for $250 per site.[73] One commenter cited a presentation by Jonah Energy at the WCCA 2015 Spring Meeting indicating that their total LDAR program costs were about $99 per inspection in the first year, decreasing to about $29 per inspection in the 5th year.[74] This commenter also cited an ICF model-based estimate of third-party contractor costs, which ranged between $491 - $793 per facility, depending on facility size, as well as a FLIR presentation with information from survey providers suggesting well-pad rates ranging from $300 - $800.[75]

If conducting the inspections itself, the operator would incur costs for any additional equipment and labor required (if the operator already has an LDAR program in place, then it may already have the adequate equipment and labor to meet the BLM LDAR requirements). Optical gas imaging equipment, such as infrared (IR) cameras, has been reported to cost between $85,000 - $124,000 per device (EPA 2014, p. 40).[76] Portable analyzers have been reported to cost $10,800 per device, plus

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72 Carbon Limits 2014, p. 32.

73 Comments submitted to the BLM on Waste Prevention, Production Subject to Royalties, and Resource Conservation Proposed Rule (proposed February 8, 2016) by Environmental Defense Fund; April 22, 2016; p. 29.

74 EDF comment, p. 30 citing WCCA Spring Meeting, Jonah Energy Presentation, May 8, 2015, delivered by Paul Ulrich.

75 EDF Comment, citing ICF Leak Detection and Repair Cost-Effectiveness Analysis (Dec. 4, 2015), and FLIR, OGI Service Provider Survey (March 2016), at 2-3 (Attachment 2).

76 Reported by Meister 2009 and ICF International 2014, respectively.

additional labor costs associated with the inspections (EPA 2014, p. 39).[77] While optical gas imaging equipment requires a larger capital investment, it can monitor more pieces of equipment per hour, with estimates ranging up to 2,100 components per hour. Portable analyzers require frequent calibration during the inspection, limiting inspection speed, and can inspect about 30-40 components per hour (EPA 2014, pp. 39-40). While the EPA references costs of $10,800 per device, the BLM identified portable detectors that cost as low as $1,000.[78]

Some commenters provided cost estimates for conducting an in-house LDAR program that were significantly higher than those used by BLM in the draft RIA for the proposed rule and also higher than the costs detailed in the CTG. These commenters' cost estimates for a third-party contractor to conduct LDAR inspections were more modest, however, although still somewhat higher than the BLM's estimates. In addition, these commenters suggested that the cost of administering an LDAR program would be slightly higher than the BLM's estimate in the proposed rule. In response to these comments and to new information available in the CTG, the BLM adjusted its cost estimates for conducting an LDAR program to match those in the CTG. We note that the CTG is specific to existing sources and provides a more direct comparison to the type of wellsites that will be covered by the BLM rule.

Costs of Repairs

Once leaks are identified, Carbon Limits finds that the average repair costs range from $56 to $189, depending on the component that is leaking. These repair cost estimates cover the equipment and replacement costs, and do not consider potential cost savings from the sale of the conserved gas.

Table 7-12a: Engineering Costs of Leak Detection Devices, Capital Costs and Annualized Costs Considering 5-year Equipment Life

Device	Capital Costs[1]	Annualized Capital Costs[1], Using Interest Rates of:	
		3%	7%
IR camera	$124,000	$27,076	$30,242
Portable analyzer	$11,000	$2,402	$2,683
Portable analyzer (midpoint)	$6,000	$1,310	$1,463
Portable detector	$1,000	$218	$244

[1] Capital costs include the equipment costs only, without potential offsets from the sale of recovered gas.

[77] Reported costs from RTI memorandum.
[78] For example, Honeywell PhD6, http://www.honeywellanalytics.com/en/products/PhD6

Table 7-12b: Total Average Leak Rate and Repair Costs by Components at Well Sites

Component	Average Leak Rate (scfm)	Repair Costs			
		Minimum	Average	Median	Maximum
Valve	0.12	$20	$90	$50	$5,500
Connector/ Connection	0.10	$15	$56	$50	$5,000
Regulator	0.12	$20	$189	$125	$1,000
Instrument Controller (Leak only)	0.14	$20	$129	$50	$2,000

Source: Carbon Limits 2014, p. 32

Given the value of the gas conserved by repairing a leak, Carbon Limits concludes that, once identified, the vast majority of leaks are economic to repair at a gas price of $3/Mcf (p. 16). It found that 90% of the leak volume could be repaired with a payback period of less than 1 year.

This finding is supported by experiences within the industry. In its comment letter[79] to the EPA concerning the EPA's white paper on Oil and Natural Gas Sector Leaks, Southwestern Energy indicated that through its LDAR program, the company has identified that leaking components represent less than 0.08% of the total components, and well sites with leaks represent about 20% of the total wells. Southwestern Energy carries out an inspection program that includes annual inspections of its roughly 4,660 wells and 1,730 well pads. It also indicated that 89% of the leaks are repaired upon discovery and 100% of leaks are repaired within 15 days of discovery. It has found that the majority of leaky components were connectors that were easily repairable at no replacement cost and no significant personnel cost. This generally supports the claim that most leaks are easy, and therefore cost effective, to repair.

Uncertainties

Potential leak reductions and volumes of gas conserved are expected to vary depending on the frequency of the inspection program, but the precise relationship between inspection frequency and the expected reduction in the volume of gas lost through leaks is uncertain. In its regulatory analysis for the Colorado AQCC regulations, the Colorado Department of Public Health and Environment used potential leak reduction rates of 40% for annual LDAR inspections, 60% for quarterly LDAR inspections, and 80% for monthly LDAR inspections (CO 2014, p. 49). ICF (2015) used an assumed a leak reduction rate of 60% for its analysis of quarterly LDAR. Carbon Limits (2014) examined potential emissions reductions scenarios for a single survey and determined that potential leak reductions of 94.5% are obtainable if the operator repairs all of the leaks that it identifies. In both the TSD for the NSPS Subpart OOOOa and later the Control Techniques Guidelines for the Oil and Natural Gas Industry, the EPA assumed a 40%, 60%, and 80% emissions reductions for annual, semi-annual, and quarterly inspection frequency programs, respectively. In this analysis, we have

[79] Southwestern Energy 2014, p. 9.

used the same assumptions as EPA and the Colorado Department of Public Health and Environment—a 40% reduction for annual surveys, 60% reduction for semi-annual surveys, and 80% reduction for quarterly surveys.

In addition, there are a number of other significant sources of uncertainty in estimating the benefits of LDAR requirements. First, as discussed in the preamble, recent studies continue to suggest that the GHG Inventory estimates (which the EPA and the BLM use for these analyses) of volumes of methane released through leaks are too low, and perhaps significantly too low. In particular, there is evidence that a substantial proportion of the gas lost through leaks is lost through low frequency high volume events (referred to as losses at "super-emitters"). If a substantially larger volume of gas is actually being lost through leaks than projected, the LDAR requirements will produce substantially larger benefits than estimated here in terms of the volumes of saved gas and avoided methane releases.

Second, we have reason to believe that many operators currently conduct some LDAR activities on oil and gas wells on Federal and Indian leases and would continue to do so absent this rule, although the extent to which they are using optical gas imaging or portable analyzers, and the frequency of their inspections, are unknown.[80] We would not expect incremental costs or benefits for any operators that currently administer an LDAR program that already meets the requirements of the rule.

Third, the final rule exempts sites that contain only a wellhead or wellheads, and no other equipment. We believe that these sites are less likely to lose significant volumes of gas through leaks, compared to other sites, and thus their exclusion should improve the cost-effectiveness of the final rule. We do not have any information, however, on how many sites fall into this category, and thus we do not know how much their exclusion will reduce costs and benefits.

Fourth, this analysis uses inputs developed by the EPA for the Control Technique Guidelines, but we have reason to believe that those inputs may substantially underestimate the benefits of the BLM LDAR requirements. While we have tried to align the BLM LDAR and EPA fugitive emissions programs as much as possible, the programs are different in one significant respect. The BLM LDAR requirements apply to all equipment at a site, while the EPA fugitive emissions requirements do not require inspections of most storage vessels, covers, and closed vent systems, as these are covered under separate comprehensive requirements to control emissions from those sources. Thus, the EPA analysis of the EPA fugitive emissions requirements does not include the reduction of leaks from those sources. The BLM does not apply separate standards to reduce gas losses from those sources, instead requiring that they be inspected under the LDAR requirements. Additionally, the sources not subject to the EPA fugitive emissions requirements but covered by the BLM LDAR requirements—storage vessels, in particular—appear to be a very significant source of lost gas, based on recent studies. As noted in the preamble, Section III., the Lyon et al. study, a helicopter survey of over 8,000 oil and gas wells, reported that over 90 percent of the detected emission incidences were from tanks. Moreover, the Lyon et al. study was only picking up the largest leaks, which could be detected from the air. Similarly, the Colorado State University studies found

[80] For example, EPA stated that it EPA "has found that owners and operators are voluntarily using [Optical Gas Imaging] systems to detect leaks. However, the EPA does not know the extent of these voluntary efforts within the industry on a national level" (EPA 2014, p. 42).

substantial venting at tanks, and the City of Fort Worth study found that thief hatches are the largest source of fugitive emissions.

Conversely, the BLM also received comments during the public comment period and during Executive Order 12866 meetings with OMB indicating that leak rates and leak emissions are lower than the estimates presented by the EPA in its analysis of the NSPS Subpart OOOOa and CTG (again, noting that the EPA figures do not include leaks from storage vessels) and which we used in this analysis. Lower leak rates and lower emissions associated with those leaks would result in lower benefits and net benefits than those estimated for the LDAR requirements.

Analyses of Costs and Benefits

The BLM is aware of several detailed analyses of the costs and gas savings attributable to leak detection requirements: the Carbon Limits study; ICF (2015); and the model plant analyses that EPA used in the OOOOa rulemaking and the development of the CTGs. Here, we review all three analyses, and use the EPA data to produce cost and benefit estimates for the final rule LDAR requirements and to conduct a sensitivity analysis of how those costs and benefits might be affected by requiring different inspection frequencies for certain sources. We note, however, that while the EPA data allows for the most detailed cost estimates and comparisons across different scenarios, the actual results likely understate the benefits of the BLM provisions, and may substantially understate them.

Carbon Limits considered the full costs of an LDAR program, including inspections, repairs, and value of the conserved gas. This study found an average NPV of -$35 per survey on well sites and batteries using a discount rate of 7% and an average NPV of $21 per survey on well sites using a discount rate of 3% (Carbon Limits 2015b). A negative NPV indicates that the average survey posed a net cost to the operator, while a positive NPV indicates that the average survey posed a net savings to the operator. The analysis included observations for 1,764 surveys on wellsites and well batteries that were generally conducted annually or bi-annually (i.e., once every two years).

Carbon Limits (2014) also examined the impacts of increased inspection frequencies using a subset of the data where multiple inspections were conducted on the facilities and for which it could ascertain reliable frequency information. Carbon Limits determined that increasing the LDAR survey frequencies would achieve greater emissions reductions, since leaks can be identified and repaired earlier. However, more frequent inspections would also increase the overall costs, with additional surveys being conducted, and the per-survey benefits would be expected to decline as surveys become more frequent and the number of undiscovered leaks declines.

Carbon Limits (2015b) estimated average NPVs of $2,435, $854, and -$2,401 for annual, semi-annual, and quarterly LDAR programs on well sites and batteries, respectively, using a discount rate of 7%. The researchers estimated average NPVs of $2,666, $1,051 and -$2,220 for annual, semi-annual, and quarterly LDAR programs on well sites and batteries, respectively, using a discount rate of 3%. Again, negative NPVs indicate that the average LDAR program for a well site or battery would pose a net cost to the operator, while a positive NPV indicates cost savings. These data, in Table 7-12c, show that the average costs of LDAR programs on well sites or batteries increases with the inspection frequency. The data also indicate that there could be a difference in the wellsites and well batteries in the full dataset (1,764 survey observations) and those in the subset (62 survey observations). Overall, Carbon Limits (2015b) finds that, requiring semi-annual LDAR inspections

for wellsites and well batteries would produce net cost savings to the operator, while a quarterly inspection requirement would pose net costs to the operator.

Other research indicates that LDAR programs produce cost savings for operators at well pads, gathering and processing facilities, even with quarterly inspections. ICF (2015) estimates that an LDAR program with quarterly inspections would result in cost savings of $7,334, $36,768, and $12,214, for well pads, gathering facilities, and processing facilities, respectively. This analysis uses a sales value of $4/Mcf for natural gas. For well pads, ICF estimates annual inspection costs of $1,084 (for all 4 inspections), initial set-up costs of $108, and labor repair costs of $813, which are offset by a value of the recovered gas of $9,340 (p. 2).

Table 7-12c: Carbon Limits - Average NPV for LDAR Programs, by Inspection Frequency

	NPV using a 7% Discount Rate				
		Inspection Frequency[2]			
Site or Facility	**All Surveys[1]**	**Annual**	**Semi-Annual**	**Quarterly**	**Monthly**
Compressor station	$3,376	$2,890	($466)	($7,319)	($34,886)
Wellsite and well battery	($35)	$2,435	$854	($2,401)	($15,521)
	NPV using a 3% Discount Rate				
		Inspection Frequency[2]			
Site or Facility	**All Surveys[1]**	**Annual**	**Semi-Annual**	**Quarterly**	**Monthly**
Compressor station	$3,881	$3,349	($56)	($6,934)	($34,519)
Wellsite and well battery	$21	$2,666	$1,051	($2,220)	($15,351)

Source: Carbon Limits (2015b).

[1] Surveys numbered 1,915, 614, and 1,764 for the compressor station, gas plant, and wellsite and well battery categories, respectively.

[2] NPV should be considered as the cost to implement the LDAR program for the average well with the given inspection frequency (and not the cost per inspection). Surveys numbered 268, 87, and 61 for the compressor station, gas plant, and wellsite and well battery categories, respectively. These surveys were a subset of the larger dataset and included sites and facilities that Carbon Limts was able to ascertain frequency information.

The EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry lists per-wellsite costs and emissions reductions of implementing an LDAR program with annual, semi-annual, and quarterly OGI inspections, as well as LDAR programs using Method 21 inspections of repair criteria. For the most part, the OGI programs, irrespective of frequency, are less costly than the Method 21 programs. Unlike the Carbon Limits and ICF cost estimates, the EPA estimates include not only capital and operations or third-party provider costs, but also additional costs that an operator might encounter when developing and implementing a comprehensive company-wide LDAR program, such as reading the EPA's requirements, developing the monitoring plan, and the costs of repairs, resurveys, documentation, etc. Note also, however, that the EPA emissions reduction and incremental production estimates are understated with respect to the BLM LDAR program, as discussed above.

Table 7-12d: Per Facility Annual Costs and Emissions Reductions for OGI Monitoring and Repair Programs at Wellsites

Frequency of OGI Monitoring and Repair	Well Site Type	Annualized Cost Per Facility ($)[1]		Emissions Reduction Per Facility (tpy)[2]		Incremental Production Per Facility (Mcf)[3]
		7% Discount rate	3% Discount rate	Methane	VOC	
Annual	Gas wellsite	$1,318	$1,299	2.19	0.61	127
	Oil wellsite <300 GOR	$1,318	$1,299	0.50	0.13	29
	Oil wellsite >300 GOR	$1,318	$1,299	1.10	0.30	64
Semi-annual	Gas wellsite	$2,285	$2,265	3.29	0.917	191
	Oil wellsite <300 GOR	$2,285	$2,265	0.74	0.199	43
	Oil wellsite >300 GOR	$2,285	$2,265	1.66	0.451	96
Quarterly	Gas wellsite	$4,220	$4,197	4.38	1.222	254
	Oil wellsite <300 GOR	$4,220	$4,197	0.98	0.265	57
	Oil wellsite >300 GOR	$4,220	$4,197	2.21	0.602	128

[1] Costs do not consider the value of the gas recovered. See CTG, pp. 9-25 – 9-27. The costs using a 3% discount rate are calculated using the EPA data.
[2] Methane Reductions calculated by converting the gas savings, see footnote 3; does not include emissions reductions from leak detection at certain sources covered by the BLM LDAR requirements.
[3] Inferred from the difference in per-facility costs with and without the value of the gas recovered, using a $4/Mcf natural gas price, the price used in the CTG; does not include emissions reductions from leak detection at certain sources covered by the BLM LDAR requirements.

To apply these EPA estimates to the BLM LDAR requirements, we estimated the number of existing wellsites that would be impacted by the rule. First, we identified the number of producing oil and gas wells on Federal and Indian leases. Next we removed the wells in Colorado and Wyoming (in the Upper Green River Basin). Colorado has existing LDAR requirements and Wyoming's new requirements will take effect on January 1, 2017. To calculate the number of impacted wellsites (as opposed to wells), we assumed 2 wells per wellsite, consistent with EPA's assumption based on analysis that it conducted. This yields a total of 36,690 existing wellsites (about 20,660 gas wellsites and 16,030 oil wellsites) that would be impacted by the final rule. The number of impacted wellsites will decline over time, however, as wells are plugged or recompleted , and recompleted and new wells will be covered by the Subpart OOOOa requirements.

Table 7-12e: Derivation of Impacted Well Sites

Metric	Federal		Indian	
	Gas	Oil	Gas	Oil
Number producing wells[1]	52,131	28,510	6,443	5,292
Number of wells in CO and WY (GRB)[1]	15,457	1,357	1,795	388
Number of impacted wells	36,674	27,153	4,648	4,904
Number of wells per site[2]	2	2	2	2
Number of wellsites impacted by the rule	18,337	13,577	2,324	2,452

[1] Data from AFMSS, as of January 1, 2015.
[2] Basis for assumption provided in the TSD for the NSPS Subpart OOOOa rule.

Based on these activity data and the per-facility cost, incremental production (or gas recovery) per wellsite, and emissions reductions data from the CTG, we estimate the impacts of the BLM's final LDAR requirements and alternative approaches that we evaluated. We used the EPA's CTG information, because we believe it represents an approximate picture of what a company would have to undertake to implement an LDAR program, and because it includes detailed data that allow us to conduct more detailed sensitivity analyses of different approaches. Specifically, the CTG data differentiates between potential natural gas releases and potential reductions (or gas savings) from oil wells with a GOR of less than 300 and a GOR of more than 300. The EPA's analysis for the NSPS Subpart OOOOa did not make that distinction. We recognize, however, that if we used per-facility or per-inspection cost data from other sources then that the result would show lower compliance costs. For example, if we used the Carbon Limits cost estimate of $35 per well inspection (7% discount rate), then the total cost of the rule's LDAR requirement would be estimated as $2.6 million per year. In addition, because the CTG emissions reductions data exclude some significant sources covered by the BLM program, as discussed earlier, we believe the benefits estimates presented here are underestimated, and may be significantly underestimated.

We present below the results for the final rule requirements and four alternative approaches: (1) the approach in the final rule of semi-annual inspections for all wells; (2) quarterly inspections for all wells; (3) semi-annual inspections for all wells and annual inspections for wells with a GOR of less than 300; (4) semi-annual inspections with an exemption for wells with a GOR of less than 300; and (5) annual inspections for all wells. We analyzed many other possible approaches, including approaches that reduced inspection frequency for low production wells, but only include here those alternative approaches that we selected as the most viable in reducing waste of gas and releases of methane at a reasonable cost. Thus, we include approaches that maintain most of the benefits produced by semi-annual inspections while reducing costs.

The summary results of the final rule and alternative approaches are shown in Tables 7-12f and 7-12g with the details of each approach provided in the appendix. The cost estimates are in 2012 dollars, and the cost savings estimates use projected natural gas prices, as described in Section 7.5. Estimates are presented as annual impacts from 2017 to 2026.

Final Rule: Semi-Annual Inspections:

Estimated annual impacts:

- Impact up to 36,700 wellsites per year;
- Costs of about $83 – 84 million per year;
- Cost savings of about $12 – 21 million per year*;
- Monetized benefits of the reduced methane emissions of $96 – 123 million per year* (using the model average at the 3% discount rate);
- Net benefits of $25 – 60 million per year* in 2017 – 2026;
- Increase gas production by 5.2 Bcf per year*;
- Reduce methane emissions by 89,500 tons per year*; and
- Reduce VOC emissions by 24,800 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $625 – 630 million (NPV using a 7% discount rate) or $730 – 737 million (NPV using a 3% discount rate);
- Total cost savings of of $128 million (NPV using a 7% discount rate) or $152 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $96 million (NPV using a 7% discount rate) or $123 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $315 – 321 million (NPV using a 7% discount rate) or $380 – 386 million (NPV using a 3% discount rate)*.

Alternative 1.: Quarterly Inspections

Estimated annual impacts:

- Impact up to 36,700 wellsites per year;
- Costs of about $154 – 155 million per year;
- Cost savings of about $16 – 27 million per year*;
- Monetized benefits of the reduced methane emissions of $128 – 163 million per year* (using the model average at the 3% discount rate);
- Net benefits ranging from a net cost of $10 million to a net benefit of $36 million per year*;
- Increase gas production by 6.9 Bcf per year*;
- Reduce methane emissions by 119,000 tons per year*; and
- Reduce VOC emissions by 33,000 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $1.16 billion (NPV using a 7% discount rate) or $1.36 billion (NPV using a 3% discount rate);
- Total cost savings of of $171 million (NPV using a 7% discount rate) or $202 million (NPV using a 3% discount rate)*;

- Total monetized social benefit from the reduction of methane emissions of $128 million (NPV using a 7% discount rate) or $163 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $94 – 97 million (NPV using a 7% discount rate) or $125 – 129 million (NPV using a 3% discount rate)*.

Alternative 2.: Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR

Estimated annual impacts:
- Impact up to 36,700 wellsites per year;
- Costs of about $78 million per year;
- Cost savings of about $12 – 20 million per year*;
- Monetized benefits of the reduced methane emissions of $95 – 121 million per year* (using the model average at the 3% discount rate);
- Net benefits of $29 – 64 million per year* in 2017 – 2026;
- Increase gas production by 5.1 Bcf per year*;
- Reduce methane emissions by 88,100 tons per year*; and
- Reduce VOC emissions by 24,400 tons per year*.

Estimated total impacts over the 10-year evaluation period:
- Total costs of $584 – 589 million (NPV using a 7% discount rate) or $683 – 689 million (NPV using a 3% discount rate);
- Total cost savings of of $126 million (NPV using a 7% discount rate) or $150 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $95 million (NPV using a 7% discount rate) or $121 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $342 – 347 million (NPV using a 7% discount rate) or $410 – 417 million (NPV using a 3% discount rate)*.

Alternative 3.: Semi-Annual Inspections and Exempt Oil Wells <300 GOR

Estimated annual impacts:
- Impact up to up to 31,100 wellsites per year;
- Costs of about $70 – 71 million per year;
- Cost savings of about $12 – 20 million per year*;
- Monetized benefits of the reduced methane emissions of $92 – 117 million per year* (using the model average at the 3% discount rate);
- Net benefits of $33 – 66 million per year* in 2017 – 2026;
- Increase gas production by 4.9 Bcf per year*;
- Reduce methane emissions by 85,300 tons per year*; and
- Reduce VOC emissions by 23,600 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $529 – 534 million (NPV using a 7% discount rate) or $618 – 624 million (NPV using a 3% discount rate);
- Total cost savings of of $122 million (NPV using a 7% discount rate) or $145 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $92 million (NPV using a 7% discount rate) or $117 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $367 – 372 million (NPV using a 7% discount rate) or $440 – 446 million (NPV using a 3% discount rate)*.

<u>Alternative 4.: Annual Inspections</u>

Estimated annual impacts:

- Impact up to up to 36,700 wellsites per year;
- Costs of about $48 million per year;
- Cost savings of about $8 – 14 million per year*;
- Monetized benefits of the reduced methane emissions of $64 – 82 million per year* (using the model average at the 3% discount rate);
- Net benefits of $24 – 48 million per year* in 2017 – 2026;
- Increase gas production by 3.5 Bcf per year*;
- Reduce methane emissions by 59,500 tons per year*; and
- Reduce VOC emissions by 16,500 tons per year*.

Estimated total impacts over the 10-year evaluation period:

- Total costs of $358 – 363 million (NPV using a 7% discount rate) or $419 – 425 million (NPV using a 3% discount rate);
- Total cost savings of of $85 million (NPV using a 7% discount rate) or $101 million (NPV using a 3% discount rate)*;
- Total monetized social benefit from the reduction of methane emissions of $64 million (NPV using a 7% discount rate) or $82 million (NPV using a 3% discount rate), using the model average at the 3% discount rate; and
- Total net benefits ranging from $266 – 271 million (NPV using a 7% discount rate) or $318 – 324 million (NPV using a 3% discount rate)*.

* Including benefits from the full set of sources covered by the BLM LDAR requirements would produce additional cost savings, gas production, methane reductions, monetized benefits, VOC reductions, and net benefits.

Comparison of Final Rule LDAR Requirements and Alternatives

The results of this analysis, illustrated in Table 7-12f, show that, among the regulatory options examined for LDAR, some variation of the semi-annual LDAR inspection requirement would maximize net benefits when compared with alternatives for either quarterly or annual LDAR inspections. The regulatory options for semi-annual LDAR inspections would result in roughly the same general levels of annual net benefits, ranging roughly from $25 - $66 million per year. Given the very substantial uncertainties identified above, and especially the known underestimate of benefits, as well as the relatively small differences in net benefits between the analyzed approaches, we have no assurance that selecting one of the alternative approaches would actually increase net benefits. In addition, the selected approach is conservative with respect to waste reduction and aligns with the EPA requirements for LDAR at new, modified, and reconstructed facilities, reducing the potential for confusion. Finally, the options for approval of new LDAR technology and for operators to design their own alternative LDAR programs with approval from the BLM, should reduce operators' costs, possibly substantially, below those estimated here.

Quarterly Inspections of Compressor Stations

As defined in the rule, a compressor station is a permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station and would require semi-annual inspections and not quarterly inspections.

The rule includes LDAR requirements, including quarterly inspections, on compressor stations that are located on Federal and Indian leases and are at a site that is upstream of or contains the approved point of royalty measurement. Few compressor stations would meet these conditions. In the few instances of compressor stations that are subject to quarterly LDAR inspection under this rule, the operator is likely to incur compliance costs for conducting an LDAR program; however, the gas savings from correcting any potential leaks are likely to offset those costs. The Carbon Limits study referenced earlier describes positive net present values for inspections performed on compressor stations which considering their larger dataset (NPV of $3,376 using a 7% discount rate and $3,881 using a 3% discount rate). However, using a small subset of that data, Carbon Limits modeled net costs for a quarterly inspection requirement (NPV of -$7,319 using a 7% discount rate and -$6,934 using a 3% discount rate).

In its NSPS Subpart OOOOa regulations, the EPA requires quarterly LDAR requirements on compressor stations. With this rule, the BLM will extend a quarterly LDAR requirement to existing compressor stations, which as we previously stated are rare. We do not have data on the number of compressor stations that will be impacted, but we expect that number to be very small. While we do not estimate total costs associated with this provision, we note the potential for per-unit inspection costs on the rare occurrence that such compressor stations exist.

Table 7-12f: Summary of Annual Impacts for LDAR Options and Alternatives, 2017 - 2026 ($ in million)*

Regulatory Options	Annual Costs[1]		Annual Cost Savings		Annual Value of CH4 Reductions	
	Capital Costs Annualized at 7%	Capital Costs Annualized at 3%	Low	High	Low	High
Quarterly Inspections	$155	$154	$16	$27	$128	$163
Semi-Annual Inspections	$84	$83	$12	$21	$96	$123
Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR	$78	$78	$12	$20	$95	$121
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$71	$70	$12	$20	$92	$117
Annual Inspections	$48	$48	$8	$14	$64	$82

Regulatory Options	Annual Net Benefits (with Capital Costs Annualized at 7%)		Annual Net Benefits (with Capital Costs Annualized at 3%)		Net Benefits over the 10 Year Period, 2017-2026 (with Capital Costs Annualized at 7%)		Net Benefits over the 10 Year Period, 2017-2026 (with Capital Costs Annualized at 3%)	
	Low	High	Low	High	NPV 7	NPV 3	NPV 7	NPV 3
Quarterly Inspections	-$10	$36	-$10	$36	$94	$125	$97	$129
Semi-Annual Inspections	$25	$60	$26	$60	$315	$380	$321	$386
Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR	$29	$63	$30	$64	$342	$410	$347	$417
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$33	$66	$33	$66	$367	$440	$372	$446
Annual Inspections	$24	$47	$25	$48	$266	$318	$271	$324

Regulatory Options	Annual Prod. (Bcf)	Annual Royalty		CH4 Reduced (tpy)	VOC Reduced (tpy)	$/Ton CH4 Reduced	
		Low	High			Capital Costs Annualized at 7%	Capital Costs Annualized at 3%
Quarterly Inspections	6.9	$2.1	$3.4	118,999	33,006	$1,301	$1,297
Semi-Annual Inspections	5.2	$1.5	$2.6	89,452	24,761	$937	$929
Semi-Annual Inspections and Annual Inspections for Oil Wells <300 GOR	5.1	$1.5	$2.5	88,098	24,374	$890	$882
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	4.9	$1.5	$2.5	85,292	23,645	$833	$825
Annual Inspections	3.5	$1.0	$1.7	59,548	16,458	$812	$800

[1] Includes the value of the minor Carbon Dioxide Emissions.

* Including benefits from the full set of sources covered by the BLM LDAR requirements would produce additional cost savings, gas production, methane reductions, monetized benefits, VOC reductions, and net benefits.

7.13 Administrative Burden

The Supporting Statement for the Paperwork Reduction Act describes the administrative burden associated with the rule. In that document, the BLM estimates a net cost burden to the industry and the BLM associated with administrative requirements of the rule of about $5.5 million per year and $1.35 million per year, respectively, in nominal terms. That burden is expected to decrease slightly over time, since the burden associated with most of the exemption requests is for the near term only. That monetized administrative burden is included in the overall costs of the rule that this analysis presents in Section 8.1.

The estimated administrative burden[81] to industry is as follows:

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $64.53/hour)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	8	16,000	1,032,480
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, and 3178.9 Form 3160-5	50	4	200	12,906
Notification to use State- or County-wide Capture Target Calculation 43 CFR 3179.7(c)(ii)	200	1	200	12,906
Request for Approval of Alternative Capture Requirement 43 CFR 3179.7(b) Form 3160-5	50	16	800	51,624
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5[82]	0	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	2	1000	64,530
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	2	10	645

[81] Estimates for the number of responses and burden hours per response were provided by BLM program staff. In some instances, the estimates may have changed from the RIA for the proposed rule.
[82] We note that the estimated number of responses is zero, because operators already comply with the requirement when they comply with the EPA's NSPS Subpart OOOO and Subpart OOOOa. The line item is retained in this table for Paperwork Reduction Act purposes only.

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $64.53/hour)**
Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500	32,265
Notification of Functional Needs for a Pneumatic Controller (43 CFR 3179.201(b)(1)) *Form 3160-5*	10	2	20	1,291
Showing that Cost of Compliance Replacement of Pneumatic Controller Would Cause Cessation of Production and Abandonment of Oil Reserves (43 CFR 3175.201(b)(4) and 3175.201(c)) *Form 3160-5*	50	4	200	12,906
Showing in Support of Replacement of Pneumatic Controller within 3 Years (43 CFR 3179.201(d)) *Form 3160-5*	100	1	100	6,453
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year (43 CFR 3179.202(b)(2)) *Form 3160-5*	100	1	100	6,453
NotificationShowing of Functional Needs for a Pneumatic Diaphragm Pump (43 CFR 3179.202(d)) *Form 3160-5*	150	1	150	9,680
Showing that Cost of Compliance Replacement of Pneumatic Diaphragm Pump Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3175.202(f) and (g) *Form 3160-5*	10	4	40	2,581
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	1	100	6,453

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $64.53/hour)**
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	4	200	12,906
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	1	5,000	322,650
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) *Form 3160-5*	250	1	250	16,133
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	50	4	200	12,906
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	40	200	12,906
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800	51,624
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	40	3,000	387,180
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100	6,453
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	.25	13,000	838,890
Leak Detection — Inspection Annual Reporting 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000	2,581,200

Type of Response	Number of Responses	Hours per Response	Total Hours	Total Wage Cost (at $64.53/hour)
Totals	**63,200**	**-**	**85,170**	**5,496,020**

The estimated administrative burden[83] to the BLM is as follows:

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $44.73/ hour)**
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	2	4,000	178,920
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, and 3178.9 Form 3160-5	50	4	200	8,946
Notification to use State- or County-wide Capture Target Calculation 43 CFR 3179.7(c)(ii)	200	0.25 (15 minutes)	50	2,237
Request for Approval of Alternative Capture Requirement 43 CFR 3179.7(b) Form 3160-5	50	8	400	17,892
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	0	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	1	500	22,365
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	1	5	224

[83] Estimates for the number of responses and burden hours per response were provided by BLM program staff. In some instances, the estimates may have changed from the RIA for the proposed rule.

Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500	22,365
Pneumatic Controllers – Notification of Functional Need 43 CFR 3179.201(b)(1) Form 3160-5	10	0.25 (15 minutes)	3	112
Pneumatic Controllers – Request for Exemption of Replacement Requirements 43 CFR 3179.201(b)(4) Form 3160-5	50	3	150	6,710
Pneumatic Controllers – Notification of Extension of Replacement Requirements 43 CFR 3179.201(d) Form 3160-5	100	0.25 (15 minutes)	25	1,118
Pneumatic Pump– Notification of Temporary Pump 43 CFR 3179.202(b)(2) Form 3160-5	100	0.25 (15 minutes)	25	1,118
Pneumatic Pump – Notification of Functional Need 43 CFR 3179.202(d) Form 3160-5	150	2	300	13,419
Pneumatic Pump – Request for Exemption of Replacement Requirements 43 CFR 3179.202(f) Form 3160-5	10	3	30	1,342
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	0.25 (15 minutes)	25	1,118
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	3	150	6,710
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	0.167 (10 minutes)	833	37,275
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	0.5 (30 minutes)	125	5,591

Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(i)(3) Form 3160-5	50	0.25 (15 minutes)	13	559
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	160	800	35,784
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	80	1,600	71,568
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	80	12,000	536,760
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	0.5 (30 minutes)	50	2,237
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305(a)	52,000	0.083 (5 minutes)	4,333	193,830
Leak Detection — Inspection Annual Reporting 43 CFR 3179.305(b) Form 3160-5	2,000	2	4,000	178,920
Totals	**63,200**	**-**	**30,117**	**1,347,119**

7.14 Royalty Free Use of Production

The requirements in 43 CFR 3168 would clarify the parameters for an operator to use production on lease without that production incurring royalty. The requirements would ensure that the royalty free use of production applies only to uses on the lease, unit, or CA. The changes do not prohibit the operator from using the production off the lease, unit, or CA; however, they would specify royalty on that production.

The requirements are consistent with current BLM policy, found in NTL-4A. While there may be a few instances where the BLM has approved the royalty free use of production off of the lease, unit, or CA, the vast majority of existing approvals are expected to be consistent with the requirements. As such, any impacts of the requirements are expected to be *de minimis*.

7.15 Change of Royalty Rate Language

The GAO originally expressed concerns about the adequacy of the BLM's onshore oil and gas fiscal system in 2007 and 2008, with two reports addressing the United States' Federal oil and gas fiscal system. The first report compared oil and gas revenues received by the United States Government to the revenues that foreign governments receive from the development of their public oil and gas resources.[84] That report concluded that the United States' oil and gas "government take" is among the lowest in the world.[85]

The second report, which focused on whether the Department of the Interior receives a fair return on the resources it manages, cited the "lack of price flexibility in royalty rates," and the "inability to change fiscal terms on existing leases," in support of a finding that the United States could be foregoing significant revenue from the production of onshore Federal oil and gas resources.[86] The GAO recommended that the U.S. Congress direct the Secretary of the Interior to convene an independent panel to review the Federal oil and gas fiscal system and establish procedures for periodic evaluation of the system going forward.

In response to the GAO's findings, the BLM and the Bureau of Ocean Energy Management (BOEM) contracted with the consulting firm Information Handling Services' Cambridge Energy Research Associates (IHS CERA) for a comparative assessment of the fiscal systems applicable to certain Federal, State, private, and foreign oil and gas resources ("IHS CERA Study").[87] The IHS CERA Study identified four factors amenable to comparison: government take, internal rate of return, profit-investment ratio, and progressivity.[88] The study also considered measures of revenue risk and fiscal system stability. Overall, the study found that, as of the time of the study, the Federal

[84] GAO, Oil and Gas Royalties: A Comparison of the Share of Revenue Received from Oil and Gas Production by the Federal Government and Other Resource Owners, GAO 07 676R, May 2007.
[85] GAO-07-676R at 2.
[86] GAO-08-691 at 6.
[87] Agalliu, I. (2011). Comparative Assessment of the Federal Oil and Gas Fiscal Systems. U.S. Department of the Interior, Bureau of Ocean Energy Management, OCS Study, available at http://www.blm.gov/wo/st/en/prog/energy/comparative_assessment.html
[88] A "progressive" royalty rate refers to a rate that increases with the quantity or price of the resource being sold.

Government's fiscal system and overall government take, in aggregate, were in the mainstream both nationally and internationally. Even within specific geographic regions, however, it estimated a wide range of government take, and its authors acknowledged that government take varies with a variety of factors, including commodity prices, reserve size, reservoir characteristics, resource location, and water depth. As a result, the study's authors favored a sliding-scale royalty system, because a sliding-scale royalty is more progressive than a fixed-rate royalty, and can also respond to changes in commodity market conditions.

In addition to the IHS CERA Study, the BLM also reviewed a separate private study conducted by the Van Meurs Corporation.[89] The study looked at a range of jurisdictions and regions across North America and provided a comparison of the oil and gas fiscal systems on Federal, State, and private lands throughout the United States and the provinces in Canada. It suggested that as of 2011, government take on Federal lands was generally lower than the corresponding take on State or private lands. The study also made several recommendations to State and Federal Governments in the United States and Canada, including that governments apply different fiscal terms to oil leases than to gas leases, based on the differing prices of oil and gas at the time the report was published.

In April 2015, the BLM published an Advanced Notice of Proposed Rulemaking (ANPR) to solicit public comments and suggestions that might be used to update the BLM's regulations related to royalty rates, annual rental payments, minimum acceptable bids, and other financial measures.[90] In preparing the ANPR, the BLM gathered information about royalty rates charged by States and private mineral holders for oil and gas activities on State and private lands, and compared those rates to rates charged for federal oil and gas resources. The data showed that the royalty rates charged on private and State lands range from 12.5 to 25 percent, and that the average rate assessed exceeds 16.67 percent.[91] The BLM received over 80,000 comments on the ANPR. The preamble of this rule discusses the content of those comments.

This rule would change 43 CFR 3100 to conform to the corresponding statutory text, which provides the BLM with flexibility to increase the royalty rate on Federal leases obtained competitively. However, the rule would not, in itself, change the royalty rate.

As stated in the preamble, the BLM does not currently anticipate increasing the base royalty rate for new competitively issued leases above 12.5 percent. Before making such a change, the BLM would announce the change at least 60 days prior to the effective date, and would provide at least 30 days for public comment. Any proposed change would be based on an assessment of comparable onshore State and private fiscal systems, and an assessment of the proposed impacts of the change on Federal revenue, on production from Federal lands, and on demand for Federal oil and gas leases relative to State and private leases. The BLM would make its assessments of these various factors available for public review during the comment period. Since the timing and the nature of any potential changes are both speculative, this analysis does not estimate the impacts of this change to the regulatory language.

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[89] PFC Energy, Van Meurs Corporation, and Rodgers Oil & Gas Consulting (2011). World Rating of Oil and Gas Terms: Volume 1—Rating of North American Terms for Oil and Gas Wells with a Special Report on Shale Plays.
[90] 80 FR 22148.
[91] 80 FR at 22151-52.

8. Summary Of Impacts

8.1 Costs Of The Rule

The estimated costs of the rule include: (1) private costs that would be assumed by the industry and (2) public costs to society from *de minimis* amounts of carbon dioxide additions (coming from the combustion of natural gas that would have otherwise been vented). The costs shown below do not include savings from the recovery of natural gas or natural gas liquids. Instead, those savings are included in the benefits section.

The estimated compliance costs are as follows (see Table 8-1).

Annual Impacts:

- Costs range from \$114 – \$279 million per year (using a 7% discount rate to annualize capital costs) or \$110 – \$275 million per year (using a 3% discount rate to annualize capital costs).

Impacts over the 10-year evaluation period:

- Total costs range from \$1.2 – 1.5 billion (NPV using a 7% discount rate) or \$1.5 – 1.8 billion (NPV using a 3% discount rate).

After reviewing the equirements, we estimate that the largest compliance costs are associated with the LDAR and capture target requirements. Since we are unable to account for existing LDAR programs, these costs are likely to overstate the true costs of the rule.

We have attempted to estimate the upper bound of potential costs, and seek comment on factors not fully accounted for that may warrant a higher estimate. Where data are available, the impacts account for activities already conducted by operators as a result of state or other federal regulations. Due to the lack of available data, these estimates may not account for voluntary actions already undertaken by operators. To the extent that operators are already in compliance with the requirements, the estimated impacts will overstate the actual impacts of the rule.

Table 8-1: Estimated Annual Total Costs ($ in million)

Estimated Costs* - Capital Costs Annualized Using a 7% Discount Rate												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$4 - 20	$8 - 29	$43 - 74	$92 - 126	$110 - 153	$84 - 132	$69 - 130	$89 - 158	$93 - 161	$371 - 615	$483 - 798
Flare Measurement	$4	$4	$4	$5	$5	$5	$6	$6	$7	$7	$39	$46
Pnumatic Controllers	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$14	$16
Pneumatic Pumps	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$33	$38
Liquids Unloading	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$44	$52
Storage Tanks	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$59	$69
LDAR	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$630	$737
Administrative Burden	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$51	$60
Total	$114	$118 - 134	$123 - 143	$159 - 189	$208 - 242	$227 - 269	$201 - 249	$186 - 247	$207 - 275	$211 - 279	$1,241 - 1,484	$1,500 - 1,816
Estimated Costs* - Capital Costs Annualized Using a 3% Discount Rate												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$4 - 20	$8 - 29	$43 - 74	$92 - 126	$110 - 153	$84 - 132	$69 - 130	$89 - 158	$93 - 161	$371 - 615	$483 - 798
Flare Measurement	$3	$4	$4	$4	$4	$5	$5	$5	$6	$6	$34	$40
Pnumatic Controllers	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$12	$13
Pneumatic Pumps	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$27	$31
Liquids Unloading	$5	$5	$5	$5	$5	$5	$5	$6	$6	$6	$40	$47
Storage Tanks	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$51	$59
LDAR	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$625	$730
Administrative Burden	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$51	$60
Total	$110	$114 - 130	$123 - 143	$155 - 185	$204 - 238	$222 - 264	$197 - 244	$182 - 243	$202 - 271	$206 - 275	$1,210 - 1,453	$1,464 - 1,780

* Includes the monetized value of the CO_2 additions which are relatively minor (less than $30,000 during any given year).

8.2 Benefits Of The Rule

The quantified benefits of the rule include: (1) private cost savings (from the sale of recovered natural gas and natural gas liquids) that would benefit the industry and (2) public benefits to society from reductions in methane emissions. Reductions in the venting and flaring of gas would have environmental benefits by reducing the amount of greenhouse gas released into the atmosphere. Methane is a greenhouse gas and the release of methane to the atmosphere has climate impacts, generally discussed in terms of its 100-year global warming potential. While methane has a shorter atmospheric lifetime than carbon dioxide, it is 25 times more efficient at trapping heat in the atmosphere relative to carbon dioxide.[92]

After reviewing the requirements, we estimate that the largest benefits are associated with the LDAR requirements. However, as mentioned in the summary of costs, since we are unable to account for existing LDAR programs, these benefits are likely to overstate the true benefits of the rule. We also estimate large relative benefits from the pneumatic controller and flaring requirements.

The estimated benefits are as follows (see Table 8.2a).

Annual Impacts:

- Benefits from costs savings range from $20 – 157 million per year;
- Benefits from reduced methane emissions range from $189 – 247 million per year, using model averages of the social cost of methane with a 3% discount rate.
- Total benefits range from $209 – 403 million per year, using model averages of the social cost of methane with a 3% discount rate.

Impacts over the 10-year evaluation period:

- Total costs savings of $603 million (NPV using a 7% discount rate) or $764 million (NPV using a 3% discount rate);
- Total monetized social benefit from the reduction of methane emissions of $1.6 billion (NPV using a 7% discount rate) or $1.9 billion (NPV using a 3% discount rate), using model averages of the social cost of methane with a 3% discount rate;
- Total benefits $2.2 billion (NPV using a 7% discount rate) or $2.7 billion (NPV using a 3% discount rate);

We estimate that the rule would reduce methane emissions by 175,000 – 180,000 tons per year and 1.8 million tons over 10 years (see Table 8-2b). We monetized these reductions and included them in the monetized benefits. We estimate that the rule would reduce VOC emissions by 250,000 – 267,000 tons per year and 2.6 million tons over 10 years (see Table 8-2c). The VOC emissions reductions are not monetized.

Overall, we predict the rule will reduce methane emissions by 35% from the 2014 estimates and reduce the flaring of associated gas by 49%, when the capture requirements are fully phased in.

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[92] Shelanski, H. and Shambaugh, J. "Strengthening tools to account for damages from greenhouse gas emissions in regulatory analysis." Web blog post. *Blog.* The White House, August 26, 2016. Web. Accessed on November 4, 2016.

Again, we believe that the estimated benefits from cost savings represent the likely upper bound of potential benefits. Where data are available, the impacts account for activities already conducted by operators as a result of state or other federal regulations. Due to the lack of available data, it may not account for voluntary actions already undertaken by operators. To the extent that operators are already in compliance with the requirements, the estimated impacts will overstate the actual impacts of the rule.

Table 8-2a: Estimated Annual Total Benefits ($ in million)

		Annual										2017-2026	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Estimated Benefits - Cost Savings ($ in million)	Capture Target Req.	$0	$20	$29	$48	$51	$64	$79	$108	$124	$120	$398	$520
	Pnumatic Controllers	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$9	$11
	Pneumatic Pumps	$2	$2	$2	$3	$3	$3	$3	$3	$3	$3	$19	$23
	Liquids Unloading	$5	$5	$6	$7	$6	$6	$7	$7	$8	$7	$48	$57
	Storage Tanks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1
	LDAR	$12	$15	$16	$18	$17	$17	$19	$20	$21	$20	$128	$152
	Total	$20	$44	$54	$76	$79	$92	$110	$140	$157	$152	$603	$764
		Annual										**2017-2026**	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Estimated Benefits - Value of Methane Reductions	Capture Target Req.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Flare Measurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$19	$19	$21	$21	$21	$23	$23	$25	$25	$25	$165	$195
	Pneumatic Pumps	$29	$29	$32	$32	$32	$34	$34	$37	$37	$37	$245	$289
	Liquids Unloading	$36	$37	$41	$42	$42	$46	$47	$51	$52	$53	$329	$390
	Storage Tanks	$8	$8	$8	$8	$8	$9	$9	$10	$10	$10	$65	$77
	LDAR	$96	$96	$105	$105	$105	$114	$114	$123	$123	$123	$817	$964
	Total	$189	$190	$207	$208	$209	$227	$227	$246	$246	$247	$1,620	$1,914
		Annual										**2017-2026**	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Total Estimated Benefits	Capture Target Req.	$0	$20	$29	$48	$51	$64	$79	$108	$124	$120	$398	$520
	Flare Measurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Pnumatic Controllers	$20	$21	$22	$23	$22	$24	$24	$26	$26	$26	$174	$205
	Pneumatic Pumps	$31	$31	$34	$34	$34	$37	$37	$40	$40	$40	$265	$312
	Liquids Unloading	$41	$42	$47	$48	$49	$53	$54	$59	$60	$60	$376	$446
	Storage Tanks	$8	$8	$9	$9	$9	$9	$9	$10	$10	$10	$66	$78
	LDAR	$109	$111	$121	$123	$123	$131	$133	$143	$143	$143	$945	$1,116
	Total	$209	$233	$262	$284	$288	$319	$337	$386	$403	$400	$2,224	$2,678

Table 8-2b: Estimated Annual Methane Reductions (tons)

Requirement	Annual										10-Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	180,000
Pneumatic Pumps	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	26,800	268,000
Liquids Unloading	33,700	34,300	34,800	35,400	35,900	36,400	37,000	37,500	38,000	38,600	361,600
Storage Tanks	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	71,000
LDAR	89,500	89,500	89,500	89,500	89,500	89,500	89,500	89,500	89,500	89,500	895,000
Total	175,000	176,000	176,000	177,000	177,000	178,000	178,000	179,000	179,000	180,000	1,775,000

Table 8-2c: Estimated VOC Reductions (tons)

Requirement	Annual										10-Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	65,000	649,000
Pneumatic Pumps	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	70,000
Liquids Unloading	121,000	123,000	125,000	127,000	129,000	131,000	132,000	134,000	136,000	138,000	1,296,000
Storage Tanks	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	32,500	325,000
LDAR	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	24,800	248,000
Total	250,000	252,000	254,000	256,000	258,000	260,000	261,000	263,000	265,000	267,000	2,586,000

8.3 Net Benefits

The net benefits are calculated as the estimated benefits minus the estimated costs of the rule. After reviewing the requirements, we estimate that the largest net benefits are associated with the pneumatic controller, liquids unloading, and LDAR requirements.

The estimated net benefits are as follows[93] (see Table 8-3a).

Annual Impacts:

- Net benefits range from \$46 – \$199 million per year (with capital costs annualized using a 7% discount rate) or \$50 – \$204 million per year (with capital costs annualized using a 3% discount rate), using model averages of the social cost of methane with a 3% discount rate.

Impacts over the 10-year evaluation period:

- Total net benefits range from \$740 million – \$1 billion (NPV using a 7% discount rate) or \$862 million – \$1.2 billion (NPV using a 3% discount rate), using model averages of the social cost of methane with a 3% discount rate.

[93] The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented previously.

Table 8-3a: Estimated Net Benefits, using model averages of the social cost of methane with a 3% discount rate ($ in million)

Net Benefits (Capital Costs Annualized at 7%) ($ MM)												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 16	$0 - 20	($26) - $4	($41 - 75)	($46 - 88)	($5 - 53)	($23) - $39	($34) - $35	($41) - $27	($217) - $26	($278) - $37
Flare Measurement	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($7)	($7)	($39)	($46)
Pnumatic Controllers	$18	$19	$21	$21	$21	$22	$23	$24	$24	$24	$160	$189
Pneumatic Pumps	$26	$27	$30	$30	$30	$33	$33	$36	$36	$36	$232	$274
Liquids Unloading	$35	$37	$41	$42	$43	$47	$48	$53	$54	$54	$332	$395
Storage Tanks	$0	$0	$1	$1	$1	$1	$1	$2	$2	$2	$7	$9
LDAR	$25	$27	$38	$39	$39	$48	$49	$59	$60	$59	$315	$380
Administrative Burden	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($51)	($60)
Total	$95	$99 - 115	$118 - 139	$95 - 126	$46 - 80	$51 - 93	$89 - 136	$138 - 199	$128 - 197	$120 - 189	$740 - 983	$862 - 1,178

Net Benefits (Capital Costs Annualized at 3%) ($ MM)												
	Annual										2017-2026	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 16	$0 - 20	($26) - $4	($41 - 75)	($46 - 88)	($5 - 53)	($23) - $39	($34) - $35	($41) - $27	($217) - $26	($278) - $37
Flare Measurement	($3)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($34)	($40)
Pnumatic Controllers	$19	$19	$21	$21	$21	$23	$23	$25	$25	$25	$163	$192
Pneumatic Pumps	$27	$28	$30	$31	$31	$33	$34	$36	$36	$36	$238	$281
Liquids Unloading	$36	$37	$42	$43	$43	$48	$49	$53	$54	$55	$337	$400
Storage Tanks	$1	$1	$2	$2	$2	$2	$2	$3	$3	$3	$15	$18
LDAR	$26	$28	$38	$40	$40	$48	$50	$60	$60	$60	$321	$386
Administrative Burden	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($51)	($60)
Total	$99	$103 - 119	$122 - 143	$99 - 130	$50 - 84	$55 - 97	$93 - 141	$142 - 204	$132 - 201	$125 - 193	$771 - 1,014	$889 - 1,214

Comparison of Benefits and Net Benefits using the Four SC-GHG Estimates

The IWG recommends calculating benefits and net benefits using all four SC-GHG estimates: 5% (average); 3% (average); 2.5% (average); and 3% (95th percentile). Table 8-3b and 8-3c present results consistent with the IWG TSD.

Table 8-3b shows the global benefit of the methane reductions estimated to result form this rule. Table 8-3c shows the estimated benefits (including costs savings and methane reductions) and the estimated net benefits (including costs, cost savigns, and methane reductions).

As stated previously, the monetized benefits and net benefits reported throughout this RIA include the "3% (average)" model values. The benefits and net benefits using other SC-GHG model estimates are shown in this section only.

Table 8-3b: Estimated Social Benefits of Methane Reductions[1] ($ in million, 2012$)

SC-GHG Model Estimate	Annual Value										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
5% (average)	$84	$88	$90	$94	$97	$103	$107	$111	$114	$118	$740	$875
3% (average)	$189	$190	$207	$208	$209	$227	$227	$246	$246	$247	$1,620	$1,914
2.5% (average)	$258	$258	$259	$277	$278	$297	$297	$316	$317	$335	$2,138	$2,523
3% (95th percentile)	$515	$517	$536	$555	$574	$593	$612	$632	$651	$671	$4,325	$5,106

[1] The SC-CH4 values are dollar-year and emissions-year specific. SC-CH4 values represent only a partial accounting of climate impacts.

Table 8-3c: Estimated Benefits and Net Benefits using the Four SC-GHG Estimates ($ in million, 2012$)

Estimated Benefits of the Rule[1, 2]			
SC-GHG Model Estimate	**Annual Range**	**10-Year Total, NPV 7**	**10-Year Total, NPV 3**
5% (average)	$104 – 271	$1,343	$1,640
3% (average)	$209 – 403	$2,224	$2,678
2.5% (average)	$278 – 488	$2,741	$3,287
3% (95th percentile)	$535 – 823	$4,929	$5,871
Estimated Net Benefits of the Rule (Capital costs annualized using 7% rate)[1, 3]			
SC-GHG Model Estimate	**Annual Range**	**10-Year Total, NPV 7**	**10-Year Total, NPV 3**
5% (average)	($73) – $65	($141) – $103	($176) – $139
3% (average)	$46 – 199	$740 – 983	$862 – 1,178
2.5% (average)	$116 – 277	$1,257 – 1,500	$1,471 – 1,787
3% (95th percentile)	$411 – 612	$3,445 – 3,688	$4,055 – 4,370
Estimated Net Benefits of the Rule (Capital costs annualized using 3% rate)[1, 3]			
SC-GHG Model Estimate	**Annual Range**	**10-Year Total, NPV 7**	**10-Year Total, NPV 3**
5% (average)	($69) – $69	($110) – $133	($140) – $176
3% (average)	$50 – 204	$771 – 1,014	$899 – 1,214
2.5% (average)	$120 – 281	$1,288 – 1,531	$1,508 – 1,823
3% (95th percentile)	$415 – 617	$3,476 – 3,719	$4,091 – 4,407

[1] The SC-CH4 values are dollar-year and emissions-year specific. SC-CH4 values represent only a partial accounting of climate impacts.

[2] Benefits include cost savings and the social benefit of methane reductions.

[3] Net benefits include costs, cost savings, and the social benefit of methane reductions.

8.4 Distributional Impacts

8.4.1 Energy Systems

The rule has a number of requirements that are expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases.

We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context:

- Additional natural gas production ranging from 9 – 41 Bcf per year (0.03 – 0.15% of the total U.S. production);
- A reduction in crude oil production ranging from 0.0 – 3.2 million barrels per year (0 – 0.07% of the total U.S. production).

Separate from the volumes listed above, we also expect 0.8 Bcf of gas to be combusted onsite that would have otherwise been vented.

Since the relative changes in production are expected to be small, we do not expect that the rule would significantly impact the price, supply, or distribution of energy.

The requirements designed to conserve gas that would otherwise be flared are expected to result in some near term gas capture and temporary deferral of some crude oil production, with those volumes expected to be produced in the future. The deferment would slow the flaring of oil-well gas, such that we expect that a large portion of gas that would have otherwise been flared would be conserved and brought to the market. The impacts of the rule's flaring limits are quite uncertain due to several factors. Regulatory action to limit flaring was undertaken by the state of North Dakota, and those efforts should reduce the overall flaring in the state by the time this rule is final; the North Dakota requirements could also drive further deployment of and improvements in on-site capture technologies over that same time-frame. As discussed previously, there is also substantial uncertainty regarding how operators will choose to meet the flaring limits. Additionally, crude oil prices are currently very low, both reducing the opportunity cost of deferred oil receipts and slowing the pace of drilling activity and potential oil-well gas flaring.

Table 8-4a: Estimated Incremental Production

Requirement	Annual										10 Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Natural Gas (Bcf)											
Capture Target Req.	0.0	7.2	9.2	13.8	15.3	19.1	21.7	27.9	31.2	31.2	176.7
Pnumatic Controllers	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10.5
Pneumatic Pumps	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.8
Liquids Unloading	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2	2.2	2.2	21.0
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
LDAR	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	51.9
Total Natural Gas	9.0	16.3	18.3	23.0	24.5	28.3	30.9	37.1	40.5	40.5	268.3
Requirement	**Annual**										**10 Years**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Crude Oil (million bbl)											
Capture Target Req.	0.0	-0.1	-0.3	-1.5	-3.0	-3.2	-2.3	-1.7	-2.1	-2.2	-16.3
Total Crude	0.0	-0.1	-0.3	-1.5	-3.0	-3.2	-2.3	-1.7	-2.1	-2.2	-16.3

8.4.2 Royalty Impacts

The rule is expected to increase natural gas production from Federal and Indian leases, and likewise, is expected to increase annual royalties to the Federal Government, tribal governments, states and private landowners.

Royalty payments are recurring income to Federal or Tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important but sometimes difficult problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.[94]

For requirements that would result in incremental gas production, we calculate the additional royalties based on that production. When considering the deferment of production that could result from the rule's flaring limit, we calculate the incremental royalty as the difference in the present value of the royalty received ten years later and the value of the royalty that would have been received now or absent the deferment.[95]

We estimate additional royalties of $3 – 10 million per year. Over the 10-year evaluation period, we estimate additional royalties of $65 million (NPV using a 7% discount rate) or $82 million (NPV using a 3% discount rate). See Table 8-4b.

[94] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available on the web at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

[95] For incremental gas production that would occur only due to estimated oil production deferment, the royalty of the value that would be received now is $0, and so the difference is therefore the present value of the royalty received in the future.

Table 8-4b: Estimated Incremental Royalty ($ in millions)

Requirement	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Natural Gas (Bcf)												
Capture Target Req.	0.0	3.1	4.2	6.7	7.1	8.0	8.8	10.8	11.6	10.5	$69.6	$90.9
Pnumatic Controllers	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	$3.2	$3.8
Pneumatic Pumps	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	$2.4	$2.9
Liquids Unloading	0.6	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.6	0.6	$6.5	$7.7
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$0.1	$0.2
LDAR	1.5	1.7	1.8	1.8	1.7	1.6	1.6	1.6	1.5	1.4	$16.0	$19.0
Total Natural Gas	2.7	6.0	7.3	9.9	10.0	10.8	11.6	13.6	14.2	13.0	$97.9	$124.5
Requirement	**Annual**										**2017-2026**	
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Crude Oil (Difference in Royalty Value of Deferred Production)												
Capture Target Req.	0.0	0.0	-0.4	-3.0	-6.3	-6.9	-4.7	-3.2	-4.0	-3.9	($32.5)	($42.2)
Total Crude	0.0	0.0	-0.4	-3.0	-6.3	-6.9	-4.7	-3.2	-4.0	-3.9	($32.5)	($42.2)
Total Net Royalty	**2.7**	**6.0**	**6.8**	**6.9**	**3.7**	**3.8**	**6.9**	**10.3**	**10.2**	**9.0**	**$65.4**	**$82.3**

8.4.3 Employment Impacts

Executive Order 13563 reaffirms the principles established in Executive Order 12866, but calls for additional consideration of the regulatory impact on employment. It states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

The rule is not expected to impact the employment within the oil and gas extraction, drilling oil and gas wells, and support activities industries, in any material way. As noted previously, the anticipated additional gas production volumes represent only a small fraction of the U.S. natural gas production volumes. Additionally, the annualized compliance costs represent only a small fraction of the annual net incomes of companies likely to be impacted (See Section 9. Initial Regulatory Flexibility Analysis). For those operations which would be impacted to the extent that the compliance costs would force the operator to shut in production, the rule has provisions that would exempt these operations from compliance. Therefore, we believe that the rule would not alter the investment or employment decisions of firms or significantly adversely impact employment. The requirements would require the one-time installation or replacement of equipment and the ongoing implementation of a leak detection and repair program, both of which would require labor to comply.

8.4.4 Impacts on Tribal Lands

The rule would apply to oil and gas operations on both Federal and Indian leases. In this section of the analysis, we estimate the costs, benefits, net benefits, and incremental production associated with operations on Indian leases, as well as royalty implications for Tribal governments. We estimated these impacts by scaling down the total impacts by the share oil wells on Indian lands and the share of gas wells on Indian Lands. From 2013 to 2015, AFMSS data indicate that oil and gas wells on Indian leases accounted for roughly 15% and 11%, respectively, of the total wells on Federal and Indian Lands.

Costs associated with operations on Indian leases. We estimate the following costs associated with the rule's provisions for operators with leases on Indian lands.

Annual Impacts:

- Costs range from \$15 – \$39 million per year (using a 7% discount rate to annualize capital costs) or \$14 – \$39 million per year (using a 3% discount rate to annualize capital costs).

Impacts over the 10-year evaluation period:

- Total costs range from \$164 – 204 million (NPV using a 7% discount rate) or \$199 – 251 million (NPV using a 3% discount rate).

Benefits associated with operations on Indian leases. We estimate the following benefits associated with the rule's provisions with respect to leases on Indian lands.

Annual Impacts:

- Benefits from costs savings range from $3 – 23 million per year;
- Benefits from reduced methane emissions range from $23 – 30 million per year, using model averages of the social cost of methane with a 3% discount rate.
- Total benefits range from $26 – 53 million per year, using model averages of the social cost of methane with a 3% discount rate.

Impacts over the 10-year evaluation period:

- Total costs savings of $85 million (NPV using a 7% discount rate) or $108 million (NPV using a 3% discount rate);
- Total social benefits $199 million (NPV using a 7% discount rate) or $235 million (NPV using a 3% discount rate);
- Total benefits $284 million (NPV using a 7% discount rate) or $343 million (NPV using a 3% discount rate);

We estimate that the rule would reduce methane emissions by about 22,000 tons per year and 218,000 tons over 10 years. We monetized these reductions and included them in the monetized benefits. We estimate that the rule would reduce VOC emissions by 30,000 – 32,000 tons per year, and 310,000 tons over 10 years. The VOC emissions reductions are not monetized.

Net benefits associated with operations on Indian leases. We estimate the following net benefits associated with the rule's provisions with respect to leases on Indian lands[96]:

Annual Impacts:

- Net benefits range from $3 – $25 million per year (with capital costs annualized using 7% and 3% discount rates).

Impacts over the 10-year evaluation period:

- Total net benefits range from $80 – 120 million (NPV using a 7% discount rate) or $92 – 144 million (NPV using a 3% discount rate).

Incremental production associated with operations on Indian leases. We estimate the following incremental production associated with the rule's provisions with respect to leases on Indian lands:

- Additional natural gas production ranging from 1.1 – 5.8 Bcf per year; and
- A reduction in crude oil production ranging from 0 – 320,000 barrels per year.

[96] The highs and lows of the benefits and costs do not occur during the same years; therefore, the net benefit ranges presented here do not calculate simply as the range of benefits minus the range of costs presented above.

Incremental royalty associated with operations on Indian leases.

We estimate additional royalties of $0.3 – 1.9 million per year. Over the 10-year evaluation period, we estimate additional royalties of $10 million (NPV using a 7% discount rate) or $12 million (NPV using a 3% discount rate).

8.4.5 Additional Considerations

In this section, we qualitatively discuss other potential impacts of the rule.

Potential impact on new drilling on Federal lands. The rule is expected to increase the costs of developing new oil and gas resources on Federal and Indian Lands. Since the EPA finalized Subpart OOOOa, then as a practical matter, this rule will only impact new liquids unloading operations, and new oil wells flaring associated gas. All of the other requirements would practically impact existing operations only.

Due to the potentially higher development costs for new operations on Federal and Indian Lands, there is the concern that these properties could become less desirable than non-Federal and non-Tribal properties. In response, operators might conceivably shift future activity away from Federal and Indian Lands to non-Federal and non-Tribal properties or, less conceivably, away from the affected areas or regions entirely.

In response to these concerns, we do not think that this rule would cause operators to shift new drilling away from Federal and Indian Lands in most, if not all, regions. However, we recognize that the requirements in this rule discourage developmental wells in regions lacking any means for capturing and transporting gas to market. We understand that, as a general industry practice, there is a strong preference to site development in areas with the capacity to transport all gas that is produced. BLM seeks comment on regions that may be disproportionately impacted by this rule. For liquids unloading, we estimate positive returns to the industry, meaning the cost savings exceed the compliance costs. The control technologies are currently available and widely used by the industry. With respect to the flaring of associated gas, given state regulations and industry activity to curb flaring, we expect that the continued build out of pipelines in the future will result in industry compliance to the rule without diminished desirability of the Federal and Indian mineral estates.

Impact on lease bids as a result of higher regulatory costs. Similar to the discussion above, there is a concern that any added and significant regulatory costs would reduce the level of bonus bids that the Federal Government would receive for new Federal leases or the upfront payments that a Tribal government would receive for its new leases. The BLM awards the rights to develop an oil and gas lease on Federal lands to the company that bids the highest amount at auction. Leases that do not receive bids may be acquired through a non-competitive process.

The concern would be that if the regulatory requirements reduce the desirability of leases on Federal lands, then as a consequence, there would be reduced demand for the leases, less competition at auction, and bonus bids would be reduced. Or similarly, that the additional compliance costs would reduce the amount that companies would be willing to pay for the Federal leases. For example, if the bonus bid for a particular lease were reduced by an amount commensurate to the compliance costs,

then the operator would effectively pass on the compliance costs to the Federal Government, or the public.

The same concern would apply to Tribal leases. The BLM does not auction oil and gas leases on Indian Lands, rather the particular Tribe leases its own properties with companies making upfront payments to the Tribal government for the rights to develop the leases. The concern remains that in response to the additional compliance costs, companies would offer less in upfront payment (effectively passing on the compliance costs to the Tribal government) or there would be less demand for leases on Indian Lands and the upfront payments would be reduced.

While the potential for lower bonus bids is of general concern, again, we do not believe that the compliance costs of the rule are significant for new leases. Since the EPA finalized Subpart OOOOa, then as a practical matter, this rule would impact new liquids unloading operations, and new oil wells flaring associated gas. All of the other requirements would practically impact existing operations only. The only scenario we envision affecting bonus bids is where the leases are being offered in an area lacking any means for capturing and transporting gas to market. When conducting a review to offer new leases for oil and gas development, BLM considers factors affecting the ability of operators to capture and transport gas to market, and will continue to emphasize this aspect in future leasing decisions.

For most, if not all new leases, we do not believe that the compliance costs are significant enough to reduce bonus bids. For liquids unloading, we estimate positive returns to the industry, meaning the cost savings exceed the compliance costs. The control technologies are currently available and widely used by the industry. With respect to the flaring of associated gas, given state regulations and industry activity to curb flaring, we expect that the continued build out of pipelines in the future will result in industry compliance to the rule without diminished desirability of the Federal and Indian mineral estates.

Indirect economic impacts in regions where flaring is in excess of the limits. In general, economic impacts can be estimated at the direct, indirect and induced levels. Direct impacts result from expenditures associated with the operations (or compliance with the regulation) and include, for example, labor, equipment, and capital. Indirect impacts result from the suppliers of the purchased goods and services used in the operations and hiring workers to deliver those goods and services. These “2nd round” impacts would not occur if not for the operations themselves. Induced impacts result from the employees of the operations and suppliers at a household level.

While we might expect that the requirements of the rule would generate positive indirect or induced impacts through equipment purchases, infrastructure investments, or contracted services that would be provided by suppliers or service providers, we might also expect that the rule would generate negative indirect or induced impacts if operators choose to reduce investment and thereby reduce transactions made with suppliers or service providers.

Of particular interest is the operator or industry response in regions where oil-well gas flaring is the highest and where the operator might not achieve the gas capture targets. The BLM believes that the estimates of impacts in this analysis may be overstated to the extent current and pending state regulations require operators to capture more gas. Several aspects of the rule were designed to account for ongoing state efforts, including the flexibility to issue variances upon a determination by

the BLM that a state or tribal government's regulation meets or exceeds the requirements of BLM's respective provision(s).

Concerns that changes required under this rule would trigger permitting requirements. Stakeholders have raised concerns that operators might need to obtain regulatory approvals, such as rights of way or Clean Air Act permits, for various actions required by the rule. We do not believe that actions to comply with the requirements would "modify" a source for purposes of triggering Clean Air Act and state permitting requirements applicable to new and modified sources. The definition of "modification" requires both a physical change and an increase in emissions. Actions to comply with the rule, such as replacing pneumatic controllers and pneumatic pumps, installing automatic lifts, and routing gas releases to a flare, would all reduce, rather than increase emissions.

The BLM recognizes that some options for complying with the flaring limits might require additional notification to BLM or regulatory approvals for rights of way. For example, if an operator chooses to comply with using on-site capture equipment, the operator will need to file a Sundry Notice with the BLM to convey changes to the well site including an updated site facility diagram. Many operators ensure that their initial NEPA analysis at the well or field development permitting stage is sufficiently broad to include the potential impacts from these sorts of changes to the site plan, but in some cases, an operator might need to supplement the pre-existing NEPA analysis to account for the additional environmental impacts from adding capture equipment to the site. Similarly, some operators may need to file for a use authorization to obtain approval for new rights of way for adding gathering lines to connect wells to gas pipelines.

Impact on exising wells and potential concerns over premature abandonment. Depending on the lease and the requirement, the rule might increase the costs for operators with existing leases on Federal and Indian Lands. One concern is whether the existing wells can economically support these additional costs or whether the operator would respond by prematurely abandoning the well. We generally believe that the cost savings available to operators would exceed the compliance costs or that the compliance costs would not be as significant as to force the operator to prematurely abandon the well. However, we recognize that some existing leases might not support the investments and therefore include exemption clauses for requirements if compliance would force the operator to prematurely abandon the well.

We note also that specific requirements are likely to impact existing wells that are classified as marginal (those with low production volumes making their economic viability "marginal") or stripper wells (generally classified as 15 barrels of oil equivalent per day). For example, these wells are may have existing production equipment, like high-bleed continuous pneumatic controllers or uncontrolled diaphragm pneumatic pumps, that might require replacement, or the wellsites are subject to the LDAR or liquids unloading requirements. However, these wells are highly unlikely to have uncontrolled storage tanks that would require control and would not have large enough oil-well gas flaring volumes to garner compliance.

We note that when the operator abandons a marginal well, it removes the surface equipment and forfeits the lease. Replacing the equipment in the future to recover marginal amounts of production is likely to be cost prohibitive. BLM does not anticipate this scenario occurring because of the ability to issue exemption clauses where appropriate, and therefore the cost of foregone hydrocarbon reserves are not included in the rule.

9. Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA) (5 U.S.C.§ 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. § 605(b)). For final rules, the agency is required to publish a final regulatory flexibility analysis (FRFA).

Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 1,250 employees (or revenues of less than $27.5 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.[97]

Based on the analysis below, the BLM believes that the rule will not have a significant economic impact on a substantial number of small entities. Although the rule will affect a substantial number of small entities, the BLM does not believe that these effects will be economically significant. As described in more detail below, the screening analysis conducted by the BLM estimates the average reduction in profit margin for small companies will be just a fraction of one percentage point, which is simply not a large enough impact to be considered significant.

Although it is not required, the BLM nevertheless chose to prepare an initial regulatory flexibility analysis with the proposed rule and this final regulatory flexibility analysis with the final rule. There are several factors driving this decision. First, although the projected costs are expected to be quite small, as a percentage of a typical firm's annual profits, there is significant uncertainty associated with these costs. There is a combination of factors contributing to the uncertainty associated with the costs of this rule. These factors include limited data, a wide range of possible variation in commodity prices over time, and a variety of possible compliance options, particularly with respect to the associated gas flaring requirements.

Thus, given the unique circumstances present in this rulemaking, the BLM believes it is prudent, and potentially helpful to small entities, to provide an IRFA and FRFA for this rulemaking. We do not believe this decision should be viewed as a precedent for other rulemakings.

Under Section 603 of the RFA, a Regulatory Flexibility Analysis must contain:

- A description of the reasons why action by the agency is being considered;

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[97] Small Business Administration, Office of Advocacy. *A Guide for Government Agencies. How to Comply with the Regulatory Flexibility Act*. May 2012. Page 14.

- A succinct statement of the objectives of, and legal basis for, the rule;
- A description of and, where feasible, an estimate of the number of small entities to which the rule will apply;
- A description of the projected reporting, recordkeeping and other compliance requirements of the rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;
- An identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the rule; and,
- A description of any significant alternatives to the rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the rule on small entities.

9.1 Reasons why Action is Being Considered

As was described in Section 1.2 of this Regulatory Impact Analysis, OMB's Circular A-4 instructs Federal agencies to explain the need for regulatory action, such as market failure, compelling public need or social purpose. This regulatory action seeks to reduce the loss of gas from venting and flaring during operations on onshore Federal and Indian oil and gas leases. By doing so, the action aims to reduce waste in the petroleum markets and maximize revenue for taxpayers, as well as reduce the accompanying external costs imposed on society by gas which is released or flared. A 2010 GAO investigation and our subsequent analysis show that a considerable amount of natural gas is being wasted (through venting and flaring) at oil and gas production sites on Federal and Indian lands

When gas is wasted rather than captured and brought to market, society loses the ability to consume the resource. In addition, since the wasted gas in question comes from the Federal or Tribal mineral estate, the public or Tribes are often not compensated for the loss when royalty is not assessed. Additionally, state governments also lose the revenue they would ordinarily receive through royalty sharing from Federal production.

In addition to being wasted, lost gas also produces air pollution, which imposes costs to society that are not reflected in the market price of the goods. These uncompensated costs to society are referred to as negative externalities. Gas that is vented to the atmosphere or flared contributes greenhouse gases (GHG), volatile organic compounds (VOCs), and hazardous air pollutants that have negative climate, health, and welfare impacts.

Several market inefficiencies occur when society bears the costs of the damages instead of the producer. Since the damage is not borne by the producer, it is not reflected in the market price, and uncontrolled markets will produce an excessive amount of the commodity, dedicate an inadequate amount of resources to pollution control, and generate an inefficiently large amount of pollution. With stock pollutants, like methane and carbon dioxide, which build up in the atmosphere and cause damage over time, future generations bear greater a greater proportion of the burden. Further, the fact that operators do not always bear the full costs of production introduces perverse incentives to the market. Operators that voluntarily make investments to limit or avoid the loss put themselves at a competitive disadvantage in relation to operators who do not make investments.

9.2 Statement of Objectives and Legal Basis for Rule

This regulation aims to reduce the waste of natural gas from mineral leases administered by the BLM. This gas is lost during oil and gas production activities through flaring or venting of the gas, and equipment leaks. While oil and gas production technology has advanced dramatically in recent years, the BLM's requirements to minimize waste of gas have not been updated for over thirty years. The BLM believes there are economical, cost-effective, and reasonable measures that operators should take to minimize waste, which will enhance our nation's natural gas supplies, boost royalty receipts for federal taxpayers, tribes, and States, and reduce environmental damage from venting and flaring.

Flaring, venting, and leaks waste a valuable resource that could be put to productive use, and deprive American taxpayers, tribes, and States of royalty revenues. In addition, the wasted gas harms local communities and surrounding areas through visual and noise impacts from flaring, and regional and global air pollution problems of smog, particulate matter, toxic air pollution (such as benzene, a carcinogen) and climate change. The primary constituent of natural gas is methane, and gas that is wasted through venting is a major contributor to rising atmospheric methane levels.

The BLM oversees oil and gas activities under the authority of a variety of laws, including the Mineral Leasing Act of 1920 (MLA), the Mineral Leasing Act for Acquired Lands of 1947 (MLAAL), the Federal Oil and Gas Royalty Management Act (FOGRMA), the Federal Land Policy and Management Act of 1976 (FLPMA), the Indian Mineral Leasing Act of 1938 (IMLA), the Indian Mineral Development Act of 1982 (IMDA), and the Act of March 3, 1909[98].

In particular, the MLA requires the BLM to ensure that lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land…." 30 U.S.C. 225. This rule would replace current requirements related to flaring, venting, and royalty-free use of production, which are contained in Notice to Lessees-4A (NTL-4A); amend the BLM's oil and gas regulations at 43 CFR Part 3160; and add new subparts 3178 and 3179. It would apply to all Federal and Indian (other than Osage Tribe) onshore oil and gas leases as well as leases and business agreements entered into by tribes (including IMDA agreements), as consistent with those agreements and with principles of Federal Indian law.

9.3 Description and Estimate of Affected Small Entities

The small entities affected by the regulatory action include small businesses in Oil and Gas Extraction, Drilling and Support. We identify the population of affected entities in accordance with the Small Business Administration (SBA) size standards developed to carry out the purposes of the

[98] Mineral Leasing Act, 30 U.S.C. 188–287; Mineral Leasing Act for Acquired Lands, 30 U.S.C. 351–360; Federal Oil and Gas Royalty Management Act, 30 U.S.C. 1701–1758; Federal Land Policy and Management Act of 1976, 43 U.S.C. 1701–1785; Indian Mineral Leasing Act of 1938, 25 U.S.C. 396a–g; Indian Mineral Development Act of 1982, 25 U.S.C. 2101–2108; Act of March 3, 1909, 25 U.S.C. 396.

Small Business Act.[99] Based on these standards (also described below) the vast majority of businesses in the Oil and Gas Extraction, Drilling and Support sectors are considered small entities.

Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA as an individual, limited partnership, or small company considered being at "arm's length" from the control of any parent companies, with fewer than 1,250 employees. For firms drilling oil and gas wells, the threshold is 1,000 employees. For firms involved in support activities, the standard is annual receipts of less than $38.5 million.

To estimate a percentage for firms involved in oil and gas support activities we reference Tables 9-3a to 9-3b, which provide the NAICS information for firms involved in oil and gas support activities based on the size of receipts. As Table 9-3a illustrates, in 2012 the vast majority of establishments in the oil and gas sector were classified as small as defined by the SBA. Of the establishments involved in crude petroleum, natural gas, and NGL extraction, over 99% had fewer than 1,000 employees. Of the establishments involved in the drilling of oil and gas wells, over 99% had fewer than 1,000 employees.

Table 9-3a Oil and Gas Establishments by Employment Size – (2012)

NAICS	Industry	Employees	Number of Establishments	% <1000 Employees
211111	Crude Petroleum and Natural Gas Extraction	All	6398	
		< 1000	6380	99.7%
211112	Natural Gas Liquid Extraction	All	337	
		< 1000	337	100%
213111	Drilling Oil and Gas Wells	All	2179	
		< 1000	2166	99.4%
213112	Support Activities for Oil and Gas Operations	All	9659	
		< 1000	9640	99.8%

[1] The SBA size standard for the 211111 category is <1,250 employees, and <750 and <1000 for the catagories 211112 and 213111 respectively, but the 2012 Economic Census Data does not provide that level of granularity. Nonetheless, this tables provides a clear demonstration that the vast majority of Oil and Gas establishments are considered small by SBA's 2016 standards.

Source: U.S. Census Bureau, 2012 Economic Census. Mining: Industry Series: Detailed Statistics by Industry for the U.S. Query available at http://factfinder.census.gov/

[99] Code of Federal Regulations, Title 13, Chapter I, Part 121, Subpart A, Section 121.201.

Table 9-3b provides a snapshot of the oil and gas sector, including number of establishments and employees, as well as annual payroll and shipments and receipts.

Table 9-3b: Industry Statistics for the Affected Industries (2012)

NAICS	Description	Number of Establishments	Number of Employees	Annual Payroll ($1,000)	Total Value of Shipments and Receipts for Services ($1,000)
211111	Crude Petroleum and Natural Gas Extraction	6,398	161,685	13,917,174	271,148,770
211112	Natural Gas Liquid Extraction	337	14,537	1,220,786	39,811,595
213111	Drilling Oil and Gas	2,179	115,466	8,439,260	30,735,287
213112	Support Activities for Oil and Gas Operations	9,659	323,523	20,601,811	84,790,406

Source: U.S. Census Bureau, 2012 Economic Census. Mining: Industry Series: Detailed Statistics by Industry for the U.S. Query available at http://factfinder.census.gov/

Data from 2014 in Table 9-3c show that the industry is mostly "small" entities when split by number of employees; 500 and greater vs 500 and less. However, total employment and payroll are higher for the larger entities.

Table 9-3c Oil & Gas Extraction, Drilling and Support Activities by Employment Size (2014)

NAICS Code	NAICS Description	Enterprise Employment Size	Number of Firms	Number Establishments	Employment	Annual Payroll ($1,000)
211111	Crude Petroleum and Gas Extraction	<500	6,436	6,663	52,538	6,199,919
		500+	96	1,179	74,128	11,403,686
211112	Natural Gas Liquid Extraction	<500	109	118	1,859	158,597
		500+	40	296	9,314	1,094,161
213111	Drilling Oil and Gas Wells	<500	2,068	2,150	39,788	3,128,687
		500+	53	300	62,946	6,324,093
213112	Support Activities for Oil and Gas Operations	<500	9,577	9,992	138,224	10,234,463
		500+	158	1,896	169,553	16,474,022

Source: U.S. Census Bureau, Statistics of U.S. Businesses, *Number of Firms, Number of Establishments, Employment, and Annual Payroll by Employment Size of the Enterprise for the United States, All Industries 2014* – http://www.census.gov/programs-surveys/susb/technical-documentation/methodology.html

Older data in Table 9-3d for 2007, available from the U.S. Census Bureau for establishment/firm size based on receiptsshow that of the 5,880 firms in oil and gas support activities in 2007, 97 percent had annual receipts of less than $35 million.[100]

Table 9-3d: Oil and Gas Support Activities by Receipts - 2007

NAICS Code	Description	Data Type	Receipt Size		
			Total	<$35 million	>$35 million
213112	Support Activities	Firms	5,880	5,693	187
213112	Support Activities	Establishments	7,105	4,490	1,203
213112	Support Activities	Employment	247,839	86,376	161,463
213112	Support Activities	Annual Payroll ($1,000)	12,644,163	3,566,689	9,077,474

Source: U.S. Census Bureau, Special Tabulation - 2007 – (http://www.census.gov).

Based on this national data, the preponderance of entities involved in developing oil and gas resources are small entities as defined by the SBA. As such, it appears that a substantial number of small entities are potentially affected by the final rule.

9.4 Compliance Cost Impact Estimates

The BLM identified up to 1,828 entities that currently operate Federal and Indian leases and recognizes that the vast majority of these entities are small business, as defined by the SBA. We estimated a range of potential per-entity costs, based on different discount rates and scenarios considered when estimating costs to the industry. For example, using a 7% discount rate to estimate total costs, we estimate average per-entity compliance costs ranging from about $44,600 to $65,800 per-entity per year.

Table 9-4: Per-Entity Costs

Discount Rate used to Annualize Capital Costs	Capture Target Cost Scenario	Years 2017 – 2026		
		Low	High	Average
7%	Low	$24,500	$72,600	$44,600
	High	$48,000	$95,600	$65,800
3%	Low	$22,200	$70,300	$42,300
	High	$45,800	$93,400	$63,600

Recognizing that the SBA definition for a small business for oil and gas producers (21111) is one with fewer than 1,250 employees and that presents a wide range of possible oil and gas producers, the BLM looked at company data for 26 different small-sized entities that currently hold BLM-

[100] U.S. Census Bureau does not provide receipt data that allow a break at the $38.5 million threshold as defined by SBA. As such the 97 percent figure is a slight under estimate.

managed oil and gas leases. The BLM ascertained the following information from the companies' annual reports to the U.S. Securities and Exchange Commission (SEC) for 2012 to 2014.

From data in the companies' 10-K filings to the SEC, the BLM was able to calculate the companies' profit margins[101] for the years 2012, 2013 and 2014. We then calculated a profit margin figure for each company when subject to the average annual cost increase associated with this rule. For simplicity, we used the midpoint of the low and high average per-entity cost increase figures (shown above), or $55,200, recognizing this figure includes costs where the capital costs are annualized using a 7% discount rate.

For these 26 small companies, a per-entity compliance cost increase of $55,200 would result in an average reduction in profit margin of 0.15 percentage points (based on the 2014 company data).

The full detail of this calculation is available in the Appendix. As discussed above, the per-entity compliance cost figures are an average cost. Entities with higher activity levels would be subjected to a higher cost than the average. We assume small entities, as defined by SBA, would generally have lower activity levels and thus face a lower annual cost increase than the average. As such, the estimated profit margin reduction is likely to be over-estimated.

9.5 Projected Reporting, Recordkeeping and Other Compliance Requirements

The SBA has developed size standards to carry out the purposes of the Small Business Act that can be found at 13 CFR 121.201. Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA as an individual, limited partnership, or small company considered to be at "arm's length" from the control of any parent companies, with fewer than 1,250 employees. For firms drilling oil and gas wells the threshold is 1,000 employees. For firms involved in support activities the standard is annual receipts of less than $38.5 million. As shown previously, of the vast majority of firms in these industries are small businesses as defined by the SBA.

Based on the available national data, the preponderance of firms involved in developing, producing, purchasing, and transporting oil and gas from Federal and Indian lands are small entities as defined by the SBA. As such, it appears a substantial number of small entities would be potentially affected by the rule, although not significantly.

The Regulatory Impact Analysis for the final rule identifies annual costs of the rule as being between $113 and $243 million depending on the discount rate used. Greater details of the regulatory provisions are provided in the rule preamble. This section primarily discusses the paperwork burden on operators.

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101 The profit margin was calculated by dividing the net income by the total revenue as reported in the companies' 10-K filings.

The Paperwork Reduction section of the rule identifies 85,170 hours of paperwork, reporting, and recordkeeping required annually by the regulations. Using the Bureau of Labor Statistics weighted hourly rate of $64.53 per hour, the estimated hour burden to industry for this rulemaking is about $5.5 million. This burden is expected to decrease over time as requests for many of the exemptions are only relevant in the first few years.

The estimated administrative burden to industry is as follows:

Type of Response	**Number of Responses**	**Hours per Response**	**Total Hours**	**Total Wage Cost (at $64.53/hour)**
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	8	16,000	1,032,480
Request for Prior Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, and 3178.9 Form 3160-5	50	4	200	12,906
Notification to use State- or County-wide Capture Target Calculation 43 CFR 3179.7(c)(ii)	200	1	200	12,906
Request for Approval of Alternative Capture Requirement 43 CFR 3179.7(b) Form 3160-5	50	16	800	51,624
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	0	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	2	1000	64,530
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	2	10	645

Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500	32,265
Notification of Functional Needs for a Pneumatic Controller (43 CFR 3179.201(b)(1)) Form 3160-5	10	2	20	1,291
Showing that Cost of Compliance Replacement of Pneumatic Controller Would Cause Cessation of Production and Abandonment of Oil Reserves (43 CFR 3175.201(b)(4) and 3175.201(c)) Form 3160-5	50	4	200	12,906
Showing in Support of Replacement of Pneumatic Controller within 3 Years (43 CFR 3179.201(d)) Form 3160-5	100	1	100	6,453
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year (43 CFR 3179.202(b)(2)) Form 3160-5	100	1	100	6,453
NotificationShowing of Functional Needs for a Pneumatic Diaphragm Pump (43 CFR 3179.202(d)) Form 3160-5	150	1	150	9,680
Showing that Cost of Compliance Replacement of Pneumatic Diaphragm Pump Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3175.202(f) and (g) Form 3160-5	10	4	40	2,581

Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	1	100	6,453
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	4	200	12,906
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	1	5,000	322,650
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	1	250	16,133
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(e) Form 3160-5	50	4	200	12,906
Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	40	200	12,906
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800	51,624
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	40	3,000	387,180

Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100	6,453
Leak Detection — Inspection Recordkeeping 43 CFR 3179.305	52,000	.25	13,000	838,890
Leak Detection — Inspection Annual Reporting 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000	2,581,200
Totals	63,200	-	85,170	5,496,020

9.6 Related Federal Rules

In 2012, the Environmental Protection Agency (EPA) adopted Clean Air Act new source performance standards (NSPS) for certain activities in the oil and gas production sector. These regulations target reductions of volatile organic compounds (VOCs) but have the effect of reducing venting and leaks. The EPA finalized regulations that amend the 2012 NSPS for the oil and natural gas source category by setting standards for both methane and VOCs for certain equipment, processes and activities across this source category (Subpart OOOOa Rulemaking). We have described those regulations in Section 5 of this RIA.

The ongoing EPA activities do not, however, obviate the need for the BLM, in its role as a public lands manager, to update its requirements governing flaring, venting, and leaks to ensure that the public's resources and assets are protected and developed in a manner that provides for long term productivity and sustainability. First, the BLM has an independent legal responsibility, and a proprietary interest as a land manager, to oversee oil and gas production activities on Federal and Indian leases. The BLM has requirements in place, but as independent reviews have pointed out, the existing requirements pre-date, and thus do not account for, significant technological developments. Updating and clarifying the regulations will make them more effective, more transparent, and easier to understand and administer, and will reduce operators' compliance burdens in some respects. The BLM must ensure that it has modern, effective requirements to govern oil and gas operations on BLM-administered leases. Second, as a practical matter, the EPA regulations do not adequately address the issue of waste of gas from BLM-administered leases. The EPA regulations are directed at air pollution reduction, not waste prevention; they focus largely on new sources; and they do not address all avenues for reducing waste (for example, they do not impose flaring limits for associated gas). It is wholly within the BLM's statutory authority to address flaring, venting, and leaks in its capacity as a land manager with a responsibility to ensure the longevity and long term productivity of public lands and resources.

9.7 Regulatory Flexibility Alternatives

The RFA requires BLM to identify and consider (but not necessarily adopt) alternatives that minimize this final regulatory action's economic impacts on small entities. The BLM recognizes that the vast majority of business entities affected by this rule are small. Therefore, throughout the drafting of this rule, the BLM looked for regulatory alternatives in order to provide flexibility where appropriate opportunities exist. This flexibility can lessen impacts to smaller operators as well as others. The decription of the final regulation and alternatives examined are described in Section 6 of this RIA. In this section, we also describe the flexibilities that we included in the rule to minimize significant economic impacts on the regulated sector, which is includes a large number of small entities.

9.7.1 Developmental Oil Wells

The final rule requires operators submitting certain Applications for Permit to Drill (APDs) to provide information, in the form of Waste Minimization Plans, in addition to that required under existing regulation. This additional information will ensure the operator has actively explored opportunities to capture and use or sell natural gas that is expected to be produced in association with oil production, before a well is drilled.

The additional information requirement is limited to only those APDs associated with developmental oil wells. In addition, this provision minimizes burdents on operators by requiring that operators develop a plan that will work for them, rather than specifying how the operator is to reduce waste. Also, the plan is not enforceable against operators, recognizing that circumstances may change from the time of the plan to the time of the development of the well and allowing operators to adjust their approach as needed.

9.7.2 Gas Capture Targets

The final rule will establish gas capture targets for operators to meet. Whereas the rule would have required the operator to take action to limit gas flaring from each individual lease, the final rule offers greater flexibility and economic efficiency by allowing the operator to direct resources to wells or operations where it might achieve flaring reductions at the lowest marginal cost across all of that operator's flaring wells in a county or a State.

9.7.2.1 Phasing in Gas Capture Targets

Gas capture targets will be phased in gradually over a nine year period. Particularly when paired with the the opportunity to average the operator's gas capture rates across all of the operator's wells in a given State, the gradual phase-in maximizes operator's opportunities to comply in the most cost-effective manner possible.

9.7.2.2 Alternate Targets

The final rule carries forward from the rule the ability of operators to seek alternative targets in certain instances. The operator of a lease that predates the final rule may demonstrate to the BLM with engineering and economic data that meeting the specified capture percentage would impose

such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. If an operator meets this criteria, the BLM may approve an alternate capture target at the highest level that the BLM determines will not cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

9.7.3 Requirements for Pneumatic Controllers

These final regulations require operators to replace all high-bleed continuous controllers with controllers that are not high-bleed controllers. The BLM included provisions in the final rule to reduce costs associated with compliance and allow for compliance flexibility, while still preventing waste. The operator is not required to replace an existing high bleed pneumatic controllers if (1) the high bleed controller is required to meet a functional need; (2) the pneumatic controller exhaust was, as of the date of the rule, and continues to be routed to a flare device or low pressure combustor; (3) the pneumatic controller exhaust is routed to processing equipment; or (4), the operator demonstrates that replacement) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

9.7.4 Requirements for Pneumatic Pneumatic Diaphragm Pumps

The final regulations require the operator to replace a pneumatic diaphragm pump with a zero-emissions pump or route the exhaust gas to capture. The BLM included provisions in the final rule to reduce costs associated with compliance and provide compliance flexibility to operators, while still preventing waste. If the operator determines that replacing the pump with a zero-emissions pump is not viable because a pneumatic pump is necessary to perform the function, and routing to capture is technically infeasible or unduly costly, the operator may route the exhaust gas to an existing flare or combustor on site, or if there is no flare or combustor on site, the operator may take no further action. The operator also need not replace existing pneumatic pump(s)if the operator demonstrates that the cost to replace the pump(s) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

9.7.5 Storage Vessels

The final regulations require operators either to capture or combust releases from storage vessels with the potential to emit at or above 6 tpy of VOC per vessel (with exceptions to this requirement). We estimate that this would impact less than 300 storage vessels on Federal and Indian lands. The BLM included a provision in the final rule to provide operators compliance flexibility and reduce costs associated with compliance. The operator may be exempted from these provisions if the operator submits an economic analysis to the BLM that demonstrates that compliance with this requirement would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. In addition, if the uncontrolled emissions drop below 4 tpy of VOC per vessel, then the operator may remove the controls.

9.7.6 Leak Detection and Repair (LDAR) Programs

The final regulations require the operator to inspect its well sites and equipment for leaksThe BLM included in the final rule provisions to provide operators compliance flexibility and reduce costs associated with compliance. While the final rule specifies the coverage and inspection frequency for an LDAR program, an operator may also request approval of an alternative instrument-based

program if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in the regulations. In addition, the rule provides for the BLM to approve an alternative monitoring device to those specified in the rule, if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared to those specified in the rule.

10. Statutory And Executive Order Reviews

10.1 Executive Order 12866 Regulatory Planning and Review

Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to the OMB for review. A rule may be significant under Executive Order 12866 if it meets any of four criteria. A significant regulatory action is any rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

After reviewing the requirements, we have determined that the rule is an economically significant regulatory action according to the criteria of Executive Order 12866 and have prepared this regulatory impact analysis.

10.2 Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act, unless the head of the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. (see 5 U.S.C. 601 – 612). Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small businesses as defined by the SBA. As such, the rule would likely affect a substantial number of small entities. However, the BLM believes that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. Although the rule will affect

a substantial number of small entities, the BLM does not believe that these effects would be economically significant. The screening analysis conducted by BLM estimates the average reduction in profit margin for small companies will be just a fraction of one percentage point, which is not a large enough impact to be considered significant.

Although it is not required, the BLM nevertheless has chosen to prepare an Initial Regulatory Flexibility Analysis and Final Regulatory Flexibility Analysis. There are several factors driving this decision. First, although the projected costs are expected to be quite small, as a percentage of a typical firm's annual profits, there is significant uncertainty associated with these costs. There is a combination of factors contributing to the uncertainty associated with the costs of this rule. These factors include limited data, a wide range of possible variation in commodity prices over time, and a variety of possible compliance options, particularly with respect to the gas capture requirements.

Due to the fact that the rule is economically significant and impacts a substantial number of small entities, the BLM believes it is prudent, and potentially helpful to small entities, to provide an IRFA and FRFA for the rulemaking. We do not believe this decision should be viewed as a precedent for other rulemakings.

10.3 Unfunded Mandates Reform Act of 1995

Under the Unfunded Mandates Reform Act, agencies must prepare a written statement about benefits and costs prior to issuing a rule that is likely to result in aggregate expenditure by State, local, and tribal governments, or by the private sector, of $100 million or more in any one year, and prior to issuing any final rule for which a rule was published.

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, the rule is also not subject to the requirements of section 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments, because it contains no requirements that apply to such governments, nor does it impose obligations upon them.

10.4 Executive Order 13211 Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Under Executive Order 13211, agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. This Statement is to include a detailed statement of "any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increase use of foreign supplies)" for the action and reasonable alternatives and their effects.

Section 4(b) of Executive Order 13211 defines a "significant energy action" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of rulemaking, and notices of rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of [OIRA] as a significant energy action."

The incremental production of gas estimated to result from the rule's enactment represent a small fraction of the total U.S. production. Since the compliance costs represent such a small fraction of company net incomes, we also believe that the rule is unlikely to impact the investment decisions of firms. Any potential and temporarily deferred production also represents a small fraction of the total U.S. production. Due to these reasons, we do not expect that this final rule will significantly impact the supply, distribution, or use of energy. As such, the rule is not a "significant energy action" as defined in Executive Order 13211.

11. References

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12. Appendix

Appendix A-1: U.S. Methane Emissions Estimates, Onshore Natural Gas and Crude Petroleum Production Sectors, 2016 GHG Inventory

Sector	Emissions Source	Methane (Metric tons)	Methane (Bcf)	Whole gas (Bcf)
Gas	Gathering and Boosting Stations	1,864,870.3	96.8	122.9
Gas	Pneumatic Devices-gas	1,105,119.0	57.4	72.8
Gas	Liquids unloading	260,643.9	13.5	17.2
Gas	Condensate tanks	222,405.0	11.5	14.7
Gas	Pipeline Leaks	169,701.4	8.8	11.2
Gas	Chemical Injection Pumps-gas	128,876.5	6.7	8.5
Gas	Gas Engines-gas	108,783.2	5.6	7.2
Gas	Separators-gas	90,558.0	4.7	6.0
Gas	Meters/Piping	81,839.1	4.2	5.4
Gas	HF Well Completions-gas	81,664.3	4.2	5.4
Gas	Kimray Pumps	77,016.1	4.0	5.1
Gas	Compressors	73,437.3	3.8	4.8
Gas	Prod Water from CBM - Powder River	36,368.9	1.9	2.4
Gas	Gas Wells with Hydraulic Fracturing	26,791.5	1.4	1.8
Gas	Dehydrator Vents	21,357.1	1.1	1.4
Gas	Heaters	18,291.1	0.9	1.2
Gas	Non-associated Gas Wells (less fractured wells)	13,557.6	0.7	0.9
Gas	Prod Water from CBM - Black Warrior	9,767.0	0.5	0.6
Gas	Compressor Starts	7,795.9	0.4	0.5
Gas	Dehydrators	6,427.8	0.3	0.4
Gas	Compressor BD	2,835.9	0.1	0.2
Gas	Pipeline BD	2,064.0	0.1	0.1
Gas	Mishaps	1,117.2	0.1	0.1
Gas	Well Drilling	741.9	0.0	0.0
Gas	Pressure Relief Valves	534.8	0.0	0.0
Gas	Vessel BD	510.5	0.0	0.0
Gas	Gas Well Workovers without Hydraulic Fracturing	340.4	0.0	0.0
Gas	Gas Well Completions without Hydraulic Fracturing	8.7	0.0	0.0

Sector	Emissions Source	Methane (Metric tons)	Methane (Bcf)	Whole gas (Bcf)
Oil	Oil tanks	302,142.7	15.7	19.9
Oil	Chemical Injection Pumps-oil	192,887.9	10.0	12.7
Oil	HF Well Completions-oil	118,768.7	6.2	7.8
Oil	Gas Engines-oil	65,886.1	3.4	4.3
Oil	Oil Wellheads (light crude)	47,275.4	2.5	3.1
Oil	Separators-oil	26,061.7	1.4	1.7
Oil	Heaters	24,328.1	1.3	1.6
Oil	Heater/Treaters (light crude)	11,693.4	0.6	0.8
Oil	Stripper wells	11,283.8	0.6	0.7
Oil	Headers (light crude)	6,430.2	0.3	0.4
Oil	Well Blowouts Onshore	2,175.0	0.1	0.1
Oil	Compressors	1,590.5	0.1	0.1
Oil	Sales Areas	1,577.3	0.1	0.1
Oil	Well Drilling	640.3	0.0	0.0
Oil	Vessel Blowdowns	576.0	0.0	0.0
Oil	Compressor Starts	367.9	0.0	0.0
Oil	Battery Pumps	346.7	0.0	0.0
Oil	Well Completion Venting	169.6	0.0	0.0
Oil	Compressor Blowdowns	164.5	0.0	0.0
Oil	Pressure Relief Valves	135.3	0.0	0.0
Oil	Flares	132.9	0.0	0.0
Oil	Floating Roof Tanks	121.5	0.0	0.0
Oil	Well Workovers	95.0	0.0	0.0
Oil	Oil Wellheads (heavy crude)	27.4	0.0	0.0
Oil	Headers (heavy crude)	14.6	0.0	0.0
Oil	Pneumatic Devices-oil	1,567,089.1	81.4	103.3

Appendix A-2: U.S. Onshore Dry Natural Gas and Crude Oil Production and Natural Gas and Crude Oil Production on Federal and Indian Lands, in 2014, by State Jurisdiction and NEMS Region

Jurisdiction	U.S. Onshore Gas Production (MMcf)	Federal/ Indian Lands Gas Production (MMcf)	Federal/ Indian Lands % of U.S. Gas Production	U.S. Onshore Oil Production (Mbbl)	Federal/ Indian Lands Oil Production (Mbbl)	Federal/ Indian Lands % of U.S. Oil Production
Alabama	106,903	1,016	0.95%	9,828	19	0.19%
Alaska	286,627	10,502	3.66%	362,350	616	0.17%
Arizona	106	19	17.52%	56	54	96.96%
Arkansas	1,123,096	11,534	1.03%	6,845	0	0.00%
California	205,320	6,983	3.40%	204,269	14,660	7.18%
Colorado	1,546,193	454,877	29.42%	95,192	5,119	5.38%
Florida	136	0	0.00%	2,227	0	0.00%
Illinois	2,579	0	0.00%	9,547	22	0.23%
Indiana	6,616	0	0.00%	2,507	0	0.00%
Kansas	269,564	4,051	1.50%	49,510	194	0.39%
Kentucky	72,266	73	0.10%	3,376	11	0.34%
Louisiana	1,884,566	16,809	0.89%	68,356	211	0.31%
Maryland	20	0	0.00%	0	0	NA
Michigan	113,024	1,353	1.20%	7,289	-10	-0.14%
Mississippi	53,945	237	0.44%	24,346	351	1.44%
Missouri	9	0	NA	196	0	0.00%
Montana	58,261	13,253	22.75%	29,880	3,054	10.22%
Nebraska	402	1	0.33%	3,050	25	0.81%
Nevada	3	0	0.00%	316	313	99.20%
New Mexico	1,091,914	673,570	61.69%	123,686	55,842	45.15%
New York	20,201	148	0.73%	341	0	0.00%
North Dakota	275,947	29,910	10.84%	396,866	56,832	14.32%
Ohio	485,434	402	0.08%	14,918	16	0.11%
Oklahoma	2,140,250	41,208	1.93%	127,047	1,776	1.40%
Oregon	950	0	0.00%	0	0	NA
Pennsylvania	4,174,655	12	0.00%	6,692	1	0.02%
South Dakota	15,286	114	0.75%	1,798	155	8.62%
Tennessee	4,912	0	0.00%	330	0	0.00%
Texas	7,135,326	48,092	0.67%	1,155,684	490	0.04%
Utah	434,555	260,350	59.91%	40,905	23,402	57.21%
Virginia	131,885	146	0.11%	14	0	0.05%
West Virginia	982,669	156	0.02%	7,524	0	0.00%

Wyoming	1,714,292	978,683	57.09%	76,078	36,605	48.12%
Total	**24,337,912**	**2,553,500**	**10.49%**	**2,831,023**	**199,758**	**7.06%**

NEMS Region	U.S. Onshore Gas Production (MMcf)	Federal/ Indian Lands Gas Production (MMcf)	Federal/ Indian Lands % of U.S. Gas Production	U.S. Onshore Oil Production (Mbbl)	Federal/ Indian Lands Oil Production (Mbbl)	Federal/ Indian Lands % of U.S. Oil Production
East Coast	5,309,566	463	0.01%	16,798	1	0.01%
Midwest	3,386,289	77,112	2.28%	616,434	59,020	9.57%
Gulf Coast	11,395,750	751,258	6.59%	1,388,745	56,913	4.10%
Rocky Mountain	3,753,301	1,707,163	45.48%	242,055	68,180	28.17%
West Coast	493,006	17,504	3.55%	566,991	15,643	2.76%
Total	**24,337,912**	**2,553,500**	**10.49%**	**2,831,023**	**199,758**	**7.06%**

Source: U.S. natural gas and crude oil production from the EIA. Federal and Indian natural gas and crude oil production from ONRR.

Appendix A-3: Methane Emission Factors for the Natural Gas Production Stage

Emission Source Category	Unit of Measurement	National Methane Emission Factor or Range of Regional Values (Potential emissions with some exceptions)
Gas Wells		
Associated Gas Wells	NA	NA
Non-associated Gas Wells (less fractured wells)	scfd/well	7.43-42.49
Gas Wells with Hydraulic Fracturing	scfd/well	7.59-42.49
Well Pad Equipment		
Heaters	scfd/heater	14.87-67.29
Separators	scfd/separator	0.94-142.27
Dehydrators	scfd/dehydrator	23.18-106.25
Meters/Piping	scfd/meter	9.43-61.68
Compressors	scfd/compressor	263.85-312.19
Gathering and Boosting		
Gathering And Boosting Stations	scfd/station	53,066.00
Pipeline Leaks	scfd/mile	52.38-61.97
Drilling, Well Completion, and Well Workover		
Gas Well Completions without Hydraulic Fracturing	scf/completion	707.23-854.65
Gas Well Workovers without Hydraulic Fracturing	scf/workover	2,367.7-2,861.3
Hydraulic Fracturing Completions and Workovers that vent	Mg/event	36.82
Flared Hydraulic Fracturing Completions and Workovers	Mg/event	4.91
Hydraulic Fracturing Completions and Workovers with RECs	Mg/event	3.24
Hydraulic Fracturing Completions and Workovers with RECs that flare	Mg/event	4.88
Well Drilling	scf/well	2,505.9-2,965.0
Produced Water from Coal Bed Methane		
Powder River	kt/gal	2.3E-09
Black Warrior	kt/well	0.0023
Normal Operations		
Pneumatic Device Vents	scfd/device	176.74-209.12
Pneumatic Device Vents - Low Bleed (LB)	scfd/device	22.52-26.64
Pneumatic Device Vents - High Bleed (HB)	scfd/device	612.66-724.91
Pneumatic Device Vents - Intermittent Bleed (IB)	scfd/device	215.13-254.55
Chemical Injection Pumps	scfd/pump	208.89-252.30
Kimray Pumps	scf/MMscf	977.5-1,156.6
Dehydrator Vents	scf/MMscf	271.58-321.34
Condensate Tank Vents		
Condensate Tanks without Control Devices	scf/bbl	21.87-302.75
Condensate Tanks with Control Devices	scf/bbl	4.37-60.55
Compressor Exhaust Vented		
Gas Engines	scf/HPhr	0.237-0.280
Well Clean Ups		
Liquids Unloading with Plunger Lifts	scfy/venting	2,856-1,137,406

Emission Source Category	Unit of	National Methane
	well	
Liquids Unloading without Plunger Lifts	scfy/venting well	77,891-2,002,960
Blowdowns		
Vessel BD	scfy/vessel	76.86-90.94
Pipeline BD	scfy/mile	304.49-360.28
Compressor BD	scfy/compressor	3,719-4,400
Compressor Starts	scfy/compressor	8,320-9,844
Upsets		
Pressure Relief Valves	scfy/PRV	33.50-39.64
Mishaps	scf/mile	659.24-780.03

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, Annex 3.

Appendix A-4: Methane Emission Factors for the Petroleum Production Stage

Emission Classification	Emission Source Category	Unit of Measurement	Emission Factor (CH4)
Vented	Oil Tanks	scf/bbl	7.40
	Pneumatic Devices, High Bleed	scfd/controller	622.00
	Pneumatic Devices, Low Bleed	scfd/controller	23.00
	Pneumatic Devices, Int Bleed		218.00
	Chemical Injection Pumps	scfd/pump	216.00
	Vessel Blowdowns	scfy/vessel	78.00
	Compressor Blowdowns	scfy/compressor	3,775.00
	Compressor Starts	scfy/compressor	8,443.00
	Stripper wells	scfy/stripper well	2,345.00
	Well Completion Venting	scf/completion	733.00
	Well Workovers	scf/workover	96.00
	HF Well Completions, Unconterolled	scf/completion	351,146.00
	HF Well Completions, Conterolled	scf/completion	17,557.00
	Pipeline Pigging	scfd/pig station	2.40
Fugitive	Oil Wellheads (heavy crude)	scfd/well	0.13
	Oil Wellheads (light crude)	scfd/well	17.00
	Separators (heavy crude)	scfd/separator	0.15
	Separators (light crude)	scfd/separator	14.00
	Heater/Treaters (light crude)	scfd/heater	19.00
	Headers (heavy crude)	scfd/header	0.08
	Headers (light crude)	scfd/header	11.00
	Floating Roof Tanks	scfy/floating roof	338,306.00
	Compressors	scfd/compressor	100.00
	Large Compressors	scfd/compressor	16,360.00
	Sales Areas	scf/loading	41.00
	Pipelines	scfd/mile or pipeline	NE
	Well Drilling	scfd/well drilled	NE
	Battery Pumps	scfd/pump	0.24
Combusted	Gas Engines	scf/HP-hr	0.24
	Heaters	scf/bbl	0.52
	Well Drilling	scf/well drilled	2,453.00
	Flares	scf/Mcf flared	20.00
Upset	Pressure Relief Valves	scfy/PR valve	35.00
	Well Blowouts Onshore	MMscf/blowout	2.50

Source: Methane emission factors are listed in the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, Annex 3.

Appendix A-5: Social Cost of GHG Estimates

Year	SC - CO2 (2012$ per metric ton)[1]				SC - CH4 (2012$ per metric ton)[2]			
	5% Average	3% Average	2.5% Average	High Impact (95th Pct at 3%)	5% Average	3% Average	2.5% Average	High Impact (95th Pct at 3%)
2010	11	34	54	93	400	940	1,297	2,594
2011	12	35	55	97	411	984	1,297	2,702
2012	12	36	57	101	432	1,016	1,405	2,810
2013	12	37	58	105	454	1,048	1,405	2,918
2014	12	38	59	109	476	1,081	1,405	2,918
2015	12	39	61	113	486	1,081	1,513	3,027
2016	12	41	62	117	508	1,189	1,513	3,135
2017	12	42	64	121	530	1,189	1,621	3,243
2018	13	43	65	125	551	1,189	1,621	3,243
2019	13	44	66	130	562	1,297	1,621	3,351
2020	13	45	67	133	584	1,297	1,729	3,459
2021	13	45	68	136	605	1,297	1,729	3,567
2022	14	46	69	139	638	1,405	1,838	3,675
2023	14	48	70	143	659	1,405	1,838	3,783
2024	14	49	71	146	681	1,513	1,946	3,891
2025	15	50	74	149	703	1,513	1,946	3,999
2026	15	51	75	152	724	1,513	2,054	4,108
2027	16	52	76	155	757	1,621	2,054	4,216
2028	16	53	77	158	778	1,621	2,162	4,324
2029	16	53	78	161	800	1,729	2,162	4,432
2030	17	54	79	164	822	1,729	2,162	4,540
2031	17	55	80	168	854	1,729	2,270	4,648
2032	18	56	81	171	886	1,838	2,270	4,864
2033	18	57	82	174	919	1,838	2,378	4,972
2034	19	58	83	177	951	1,946	2,378	5,080
2035	19	59	84	182	973	1,946	2,486	5,297
2036	21	61	85	185	1,005	2,054	2,594	5,405
2037	21	62	88	188	1,038	2,054	2,594	5,513
2038	22	63	89	191	1,070	2,162	2,702	5,621
2039	22	64	90	195	1,081	2,162	2,702	5,837
2040	23	65	91	198	1,081	2,162	2,810	5,945
2041	23	66	92	201	1,189	2,270	2,810	6,053
2042	24	66	93	204	1,189	2,270	2,918	6,161
2043	24	67	94	208	1,189	2,378	2,918	6,269
2044	25	68	95	210	1,297	2,378	3,027	6,377
2045	25	69	96	213	1,297	2,486	3,027	6,594

2046	26	70	97	216	1,297	2,486	3,135	6,702
2047	26	71	99	219	1,405	2,594	3,135	6,810
2048	27	72	101	223	1,405	2,594	3,243	6,918
2049	27	74	102	226	1,405	2,702	3,243	7,026
2050	28	75	103	229	1,405	2,702	3,351	7,242

[1] Dollars adjusted from 2007 to 2012 based on the change in IDP-GDP. The SC-CO2 values are provided in 2007 dollars by OMB, Technical Support Document available on the web at https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf

[2] Dollars adjusted from 2007 to 2012 based on the change in IDP-GDP. The SC-CH4 values are provided in 2007 dollars by OMB, Technical Support Document available on the web at https://www.whitehouse.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf

Appendix A-6: Detail of LDAR Cost and Benefit Tables

Regulatory Options	Total Costs (Capital Costs Annualized at 7% Discount Rate)										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$155	$155	$155	$155	$155	$155	$155	$155	$155	$155	$1,164	$1,360
Semi-Annual Inspections	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$630	$737
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$78	$78	$78	$78	$78	$78	$78	$78	$78	$78	$589	$689
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$71	$71	$71	$71	$71	$71	$71	$71	$71	$71	$534	$624
Annual Inspections	$48	$48	$48	$48	$48	$48	$48	$48	$48	$48	$363	$425

Regulatory Options	Total Costs (Capital Costs Annualized at 3% Discount Rate)										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$154	$154	$154	$154	$154	$154	$154	$154	$154	$154	$1,160	$1,356
Semi-Annual Inspections	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$625	$730
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$78	$78	$78	$78	$78	$78	$78	$78	$78	$78	$584	$683
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$529	$618
Annual Inspections	$48	$48	$48	$48	$48	$48	$48	$48	$48	$48	$358	$419

Regulatory Options	Annual Benefits - Cost Savings										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$16	$19	$21	$24	$23	$23	$25	$27	$27	$27	$171	$203
Semi-Annual Inspections	$12	$15	$16	$18	$17	$17	$19	$20	$21	$20	$128	$152
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$12	$14	$16	$18	$17	$17	$19	$20	$20	$20	$126	$150
Semi-Annual Inspections (exempt oil wells <300 GOR)	$12	$14	$15	$17	$17	$17	$18	$19	$20	$19	$122	$145
Annual Inspections	$8	$10	$11	$12	$12	$12	$13	$13	$14	$13	$85	$101

Regulatory Options	Annual Cost of CO2 Additions										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.09	$0.11
Semi-Annual Inspections	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.08
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.07	$0.08
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.06	$0.08
Annual Inspections	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.05	$0.05

Regulatory Options	Annual Total Benefits - Value of CH4 Reductions										NPV 7	NPV 3
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
Quarterly Inspections	$128	$128	$140	$140	$140	$152	$152	$163	$163	$163	$1,087	$1,282
Semi-Annual Inspections	$96	$96	$105	$105	$105	$114	$114	$123	$123	$123	$817	$964

Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$95	$95	$104	$104	$104	$112	$112	$121	$121	$121	$804	$949
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$92	$92	$100	$100	$100	$109	$109	$117	$117	$117	$779	$919
Annual Inspections	$64	$64	$70	$70	$70	$76	$76	$82	$82	$82	$544	$642
Regulatory Options	**Net Benefits (Capital Costs Annualized at 7%)**										**NPV 7**	**NPV 3**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		
Quarterly Inspections	-$10	-$7	$7	$9	$8	$20	$22	$35	$36	$35	$94	$125
Semi-Annual Inspections	$25	$27	$38	$39	$39	$48	$49	$59	$60	$59	$315	$380
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$29	$31	$41	$43	$42	$51	$53	$62	$63	$62	$342	$410
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$33	$35	$45	$46	$46	$54	$56	$65	$66	$65	$367	$440
Annual Inspections	$24	$26	$32	$34	$33	$39	$40	$47	$47	$47	$266	$318
Regulatory Options	**Net Benefits (Capital Costs Annualized at 3%)**										**NPV 7**	**NPV 3**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		
Quarterly Inspections	-$10	-$7	$7	$9	$9	$21	$23	$36	$36	$36	$97	$129
Semi-Annual Inspections	$26	$28	$38	$40	$40	$48	$50	$60	$60	$60	$321	$386
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$30	$32	$42	$44	$43	$52	$53	$63	$64	$63	$347	$417
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$33	$35	$45	$47	$47	$55	$56	$66	$66	$66	$372	$446
Annual Inspections	$25	$26	$33	$34	$34	$40	$41	$47	$48	$47	$271	$324
Regulatory Options	**Royalty**										**NPV 7**	**NPV 3**
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		
Quarterly Inspections	$2	$2	$3	$3	$3	$3	$3	$3	$3	$3	$21	$25
Semi-Annual Inspections	$2	$2	$2	$2	$2	$2	$2	$3	$3	$3	$16	$19
Semi-Annual Inspections and Annual Inspections for oil wells <300 GOR	$2	$2	$2	$2	$2	$2	$2	$2	$3	$2	$16	$19
Semi-Annual Inspections and Exempt Oil Wells <300 GOR	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$15	$18
Annual Inspections	$1	$1	$1	$1	$1	$1	$2	$2	$2	$2	$11	$13

Appendix A-7: Detail of Small Business Impacts Analysis

Company	Number of Employees	Reported Total Revenue ($ in 1000s)			Reported Net Income ($ in 1000s)			Difference in Profit Margin (%)		
		2014	2013	2012	2014	2013	2012	2014	2013	2012
A	444	$2,720,632	$1,313,134	$735,718	$673,587	-$18,930	-$285,069	0.002%	0.004%	0.008%
B	384	$795,542	$974,179	$951,489	-$189,543	$117,634	$149,426	0.007%	0.006%	0.006%
C	15	$1,558,758	$1,983,388	$1,934,642	$253,285	-$553,889	$141,571	0.004%	0.003%	0.003%
D	75	$793,885	$665,257	$583,894	$265,573	$118,000	$61,654	0.007%	0.008%	0.009%
E	293	$569,428	$561,562	$709,038	-$103,100	$161,618	-$2,352,606	0.010%	0.010%	0.008%
F	159	$298,204	$197,372	$231,315	-$139,907	-$277,979	-$150,602	0.019%	0.028%	0.024%
G	300	$532,299	$485,489	$346,460	-$283,645	-$35,272	$68,637	0.010%	0.011%	0.016%
H	225	$616,207	$355,792	$319,299	$99,200	-$153,715	-$95,875	0.009%	0.016%	0.017%
I	158	$224,209	$317,502	$356,516	$120,437	$14,319	-$46,587	0.025%	0.017%	0.015%
J	247	$710,187	$520,182	$368,180	$226,343	$43,683	$55,487	0.008%	0.011%	0.015%
K	202	$472,291	$568,093	$700,195	$15,081	-$192,733	$582	0.012%	0.010%	0.008%
L	123	$133,776	$92,324	$65,664	$63,269	$38,647	-$18,791	0.041%	0.060%	0.084%
M	334	$558,633	$421,860	$231,205	$20,283	$69,184	$46,523	0.010%	0.013%	0.024%
N	27	$44,089	$35,319	$38,165	-$7,585	-$13,073	-$10,327	0.125%	0.156%	0.145%
O	21	$13,840	$17,438	$16,243	$2,884	$8,612	$38,074	0.399%	0.317%	0.340%
P	11	$12,679	$8,029	$2,264	-$34,510	$3,855	-$538	0.435%	0.688%	2.438%
Q	70	$13,208	$13,547	$12,106	$3,205	$3,542	$3,659	0.418%	0.407%	0.456%
R	419		$999,506	$248,322		-$1,222,662	-$53,885		0.006%	0.022%
S	2	$12,352	$13,126	$14,781	-$2,464	$3,353	-$2,359	0.447%	0.421%	0.373%
T	57	$171,418	$87,755	$49,940	$50,953	$49,342	-$153,791	0.032%	0.063%	0.111%
U	20	$3,221	$2,573	$2,366	-$2,152	$1,149	-$13,691	1.713%	2.145%	2.333%
V	29	$104,219	$46,223	$24,969	$28,853	$9,581	$12,124	0.053%	0.119%	0.221%
W	105	$208,553	$203,295	$180,845	-$353,136	-$95,186	-$84,202	0.026%	0.027%	0.031%
X	440	$391,469	$304,538	$159,937	-$143,474	-$222,176	-$132,708	0.014%	0.018%	0.035%
Y	164	$636,773	$431,468	$317,149	-$409,592	-$143,970	-$104,589	0.009%	0.013%	0.017%
Z	374	$1,431,289			$22,665			0.004%		
Average	**181**	**$521,086**	**$424,758**	**$344,028**	**$7,060**	**-$91,483**	**-$117,115**	**0.154%**	**0.183%**	**0.270%**

Appendix A-8: Detail Of Tribal Impacts

Table A-8a: Estimated Annual Total Costs Associated with Operations on Tribal Lands ($ in million)

Estimated Costs* - Capital Costs Annualized Using a 7% Discount Rate												
	Annual										**2017-2026**	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$1 - 3	$1 - 4	$6 - 11	$14 - 19	$17 - 23	$13 - 20	$10 - 20	$13 - 24	$14 - 24	$56 - 92	$72 - 120
Flare Measurement	$0.6	$0.6	$0.7	$0.7	$0.8	$0.8	$0.9	$0.9	$1.0	$1.0	$5.8	$6.9
Pnumatic Controllers	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.8	$2.1
Pneumatic Pumps	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$3.6	$4.2
Liquids Unloading	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$4.8	$5.7
Storage Tanks	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$7.6	$8.9
LDAR	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$10.9	$81.9	$95.8
Administrative Burden	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$6.7	$7.8
Total	$15	$15 - 18	$16 - 19	$21 - 26	$29 - 34	$32 - 38	$28 - 35	$26 - 35	$29 - 39	$29 - 39	$168 - 204	$204 - 251
Estimated Costs* - Capital Costs Annualized Using a 3% Discount Rate												
	Annual										**2017-2026**	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$1 - 3	$1 - 4	$6 - 11	$14 - 19	$17 - 23	$13 - 20	$10 - 20	$13 - 24	$14 - 24	$56 - 92	$72 - 120
Flare Measurement	$0.5	$0.5	$0.6	$0.6	$0.7	$0.7	$0.8	$0.8	$0.9	$0.9	$5.0	$6.0
Pnumatic Controllers	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.5	$1.7
Pneumatic Pumps	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$3.0	$3.5
Liquids Unloading	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$4.4	$5.1
Storage Tanks	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$6.6	$7.7
LDAR	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$81.2	$94.9
Administrative Burden	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$6.7	$7.8
Total	$14	$15 - 17	$16 - 19	$21 - 25	$28 - 33	$31 - 37	$27 - 34	$25 - 34	$28 - 38	$29 - 39	$164 - 201	$199 - 247

* Includes the monetized value of the CO2 additions which are relatively minor (less than $5,000 during any given year).

Table A-8b: Estimated Annual Total Benefits Associated with Operations on Tribal Lands ($ in million)

		Annual										2017-2026	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Estimated Benefits - Cost Savings ($ in million)	Capture Target Req.	$0.0	$3.0	$4.3	$7.1	$7.7	$9.7	$11.9	$16.2	$18.6	$18.1	$59.7	$78.0
	Pnumatic Controllers	$0.1	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.2	$1.4
	Pneumatic Pumps	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$2.1	$2.5
	Liquids Unloading	$0.5	$0.6	$0.7	$0.7	$0.7	$0.7	$0.8	$0.8	$0.8	$0.8	$5.2	$6.2
	Storage Tanks	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2
	LDAR	$1.6	$1.9	$2.1	$2.3	$2.3	$2.3	$2.5	$2.6	$2.7	$2.6	$16.7	$19.8
	Total	$2.5	$5.9	$7.5	$10.7	$11.1	$13.1	$15.7	$20.1	$22.7	$22.0	$85.1	$108.2
		Annual										**2017-2026**	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Estimated Benefits - Value of Methane Reductions	Capture Target Req.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Flare Measurement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Pnumatic Controllers	$2.5	$2.5	$2.8	$2.8	$2.8	$3.0	$3.0	$3.2	$3.2	$3.2	$21.4	$25.3
	Pneumatic Pumps	$3.2	$3.2	$3.5	$3.5	$3.5	$3.8	$3.8	$4.1	$4.1	$4.1	$27.0	$31.8
	Liquids Unloading	$4.0	$4.1	$4.5	$4.6	$4.6	$5.1	$5.2	$5.7	$5.7	$5.8	$36.2	$42.9
	Storage Tanks	$1.0	$1.0	$1.1	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3	$1.3	$8.4	$10.0
	LDAR	$12.5	$12.5	$13.7	$13.7	$13.7	$14.8	$14.8	$16.0	$16.0	$16.0	$106.2	$125.3
	Total	$23.3	$23.3	$25.5	$25.6	$25.7	$27.9	$27.9	$30.2	$30.3	$30.3	$199.2	$235.3
		Annual										**2017-2026**	
	Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Total Estimated Benefits	Capture Target Req.	$0.0	$3.0	$4.3	$7.1	$7.7	$9.7	$11.9	$16.2	$18.6	$18.1	$59.7	$78.0
	Flare Measurement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Pnumatic Controllers	$2.6	$2.7	$2.9	$2.9	$2.9	$3.2	$3.2	$3.4	$3.4	$3.4	$22.6	$26.7
	Pneumatic Pumps	$3.4	$3.4	$3.7	$3.8	$3.8	$4.1	$4.1	$4.4	$4.4	$4.4	$29.1	$34.4
	Liquids Unloading	$4.5	$4.7	$5.2	$5.3	$5.4	$5.8	$6.0	$6.5	$6.6	$6.6	$41.4	$49.1
	Storage Tanks	$1.0	$1.0	$1.1	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3	$1.3	$8.6	$10.1
	LDAR	$14.2	$14.4	$15.8	$16.0	$15.9	$17.1	$17.3	$18.6	$18.6	$18.6	$122.9	$145.1
	Total	$25.7	$29.2	$33.0	$36.2	$36.8	$41.0	$43.6	$50.3	$52.9	$52.3	$284.2	$343.4

Table A-8c: Estimated Net Benefits Associated with Operations on Tribal Lands ($ in million)

Net Benefits (Capital Costs Annualized at 7%) ($ MM)												
	Annual										**2017-2026**	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 2	$02 - 3	($4) - $1	($6 - 11)	($7 - 13)	($1 - 8)	($3) - $6	($5) - $5	($6) - $4	($33) - $4	($42) - $6
Flare Measurement	-$0.6	-$0.6	-$0.7	-$0.7	-$0.8	-$0.8	-$0.9	-$0.9	-$1.0	-$1.0	-$5.8	-$6.9
Pnumatic Controllers	$2.4	$2.4	$2.7	$2.7	$2.7	$2.9	$2.9	$3.2	$3.2	$3.2	$20.8	$24.6
Pneumatic Pumps	$2.9	$2.9	$3.3	$3.3	$3.3	$3.6	$3.6	$3.9	$3.9	$3.9	$25.5	$30.2
Liquids Unloading	$3.9	$4.0	$4.5	$4.7	$4.7	$5.2	$5.3	$5.8	$5.9	$5.9	$36.6	$43.4
Storage Tanks	$0.0	$0.0	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	$0.3	$0.3	$1.0	$1.2
LDAR	$3.3	$3.5	$4.9	$5.1	$5.0	$6.2	$6.4	$7.7	$7.7	$7.7	$41.0	$49.4
Administrative Burden	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$6.7	-$7.8
Total	$11	$12 - 14	$14 - 17	$10 - 15	$3 - 8	$3 - 9	$9 - 16	$16 - 25	$14 - 24	$13 - 23	$80 - 116	$92 - 140
Net Benefits (Capital Costs Annualized at 3%) ($ MM)												
	Annual										**2017-2026**	
Requirement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**NPV 7**	**NPV 3**
Capture Target Req.	$0	$0 - 2	$02 - 3	($4) - $1	($6 - 11)	($7 - 13)	($1 - 8)	($3) - $6	($5) - $5	($6) - $4	($33) - $4	($42) - $6
Flare Measurement	-$0.5	-$0.5	-$0.6	-$0.6	-$0.7	-$0.7	-$0.8	-$0.8	-$0.9	-$0.9	-$5.0	-$6.0
Pnumatic Controllers	$2.4	$2.5	$2.7	$2.7	$2.7	$3.0	$3.0	$3.2	$3.2	$3.2	$21.1	$25.0
Pneumatic Pumps	$3.0	$3.0	$3.3	$3.4	$3.4	$3.7	$3.7	$4.0	$4.0	$4.0	$26.1	$30.9
Liquids Unloading	$4.0	$4.1	$4.6	$4.7	$4.8	$5.2	$5.4	$5.9	$6.0	$6.0	$37.0	$44.0
Storage Tanks	$0.1	$0.1	$0.2	$0.2	$0.2	$0.3	$0.3	$0.4	$0.4	$0.4	$2.0	$2.4
LDAR	$3.4	$3.6	$5.0	$5.2	$5.1	$6.3	$6.5	$7.8	$7.8	$7.8	$41.7	$50.2
Administrative Burden	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$0.9	-$6.7	-$7.8
Total	$12	$12 - 14	$14 - 17	$11 - 15	$3 - 9	$4 - 10	$9 - 16	$16 - 25	$15 - 25	$13 - 24	$84 - 120	$97 - 144

Table A-8d: Estimated Incremental Production Associated with Operations on Tribal Lands

Requirement	Annual										10 Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Natural Gas (Bcf)											
Capture Target Req.	0.0	1.1	1.4	2.1	2.3	2.9	3.3	4.2	4.7	4.7	26.5
Pnumatic Controllers	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.4
Pneumatic Pumps	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.9
Liquids Unloading	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.3
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LDAR	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.7
Total Natural Gas	1.1	2.2	2.5	3.2	3.4	4.0	4.4	5.3	5.8	5.8	37.8

Requirement	Annual										10 Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Crude Oil (million bbl)											
Capture Target Req.	0.0	0.0	0.0	-0.2	-0.4	-0.5	-0.3	-0.3	-0.3	-0.3	-2.4
Total Crude	0.0	0.0	0.0	-0.2	-0.4	-0.5	-0.3	-0.3	-0.3	-0.3	-2.4

Table A-8e: Estimated Methane Reductions Associated with Operations on Tribal Lands (tons)

Requirement	Annual										10-Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	23,400
Pneumatic Pumps	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	29,500
Liquids Unloading	3,710	3,770	3,830	3,890	3,950	4,000	4,070	4,130	4,180	4,250	39,780
Storage Tanks	923	923	923	923	923	923	923	923	923	923	9,230
LDAR	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	116,000
Total	21,500	21,600	21,600	21,700	21,800	21,800	21,900	21,900	22,000	22,100	217,900

Table A-8f: Estimated VOC Reductions Associated with Operations on Tribal Lands (tons)

Requirement	Annual										10-Years
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2026
Capture Target Req.	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pnumatic Controllers	8,440	8,440	8,440	8,440	8,440	8,440	8,440	8,440	8,440	8,440	84,400
Pneumatic Pumps	770	770	770	770	770	770	770	770	770	770	7,700
Liquids Unloading	13,300	13,500	13,800	14,000	14,200	14,400	14,500	14,700	15,000	15,200	142,600
Storage Tanks	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	42,300
LDAR	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	32,200
Total	30,000	30,200	30,500	30,700	30,900	31,100	31,200	31,400	31,700	31,900	309,600

Table A-8g: Estimated Incremental Royalty for Tribes, ($ in millions)

Requirement	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Natural Gas (Bcf)												
Capture Target Req.	0.0	0.4	0.5	0.9	1.0	1.2	1.5	2.0	2.3	2.3	$10.44	$13.63
Pnumatic Controllers	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	$0.42	$0.50
Pneumatic Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$0.27	$0.32
Liquids Unloading	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	$0.71	$0.85
Storage Tanks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$0.02	$0.02
LDAR	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	$2.09	$2.48
Total Natural Gas	0.3	0.8	1.0	1.4	1.4	1.7	2.0	2.6	2.9	2.8	$13.95	$17.79
Requirement	Annual										2017-2026	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	NPV 7	NPV 3
Crude Oil (Difference in Royalty Value of Deferred Production)												
Capture Target Req.	$0.00	($0.01)	($0.07)	($0.51)	($1.15)	($1.35)	($0.98)	($0.72)	($0.96)	($1.01)	($4.22)	($5.48)
Total Crude	$0.00	($0.01)	($0.07)	($0.51)	($1.15)	($1.35)	($0.98)	($0.72)	($0.96)	($1.01)	($4.22)	($5.48)
Total Net Royalty	**$0.33**	**$0.77**	**$0.91**	**$0.87**	**$0.29**	**$0.34**	**$1.03**	**$1.85**	**$1.93**	**$1.80**	**$9.72**	**$12.31**

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**IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF WYOMING**

STATE OF WYOMING, et al.,	)	
Petitioners,	)	Civil Case No. 2:16-cv-00285-SWS [Lead]
v.	)	Consolidated with:
UNITED STATES DEPARTMENT OF THE INTERIOR, et al.	)	Case No. 2:16-cv-00280-SWS
Respondents.	)	Assigned: Hon. Scott W. Skavdahl

REPLY IN SUPPORT OF PETITIONERS' MOTION FOR PRELIMINARY INJUNCTION

Petitioners Western Energy Alliance (Alliance) and the Independent Petroleum Association of America (IPAA) respectfully submit this reply in support of the Petitioners' motion for preliminary injunction.

I. INTRODUCTION

Government Respondents, Intervenor-Respondents and State Respondents (collectively "Respondents") advance near-treatises on the Bureau of Land Management's (BLM) authority to

manage waste to distract the Court from the fundamental legal infirmity with this Rule: BLM has promulgated a comprehensive air quality regulatory scheme without congressional authority. Respondents' arguments cannot overcome the fact the Rule is unconstitutional, BLM's action is *ultra vires*, and this Court has the authority under the United States Constitution to make this determination. *Marbury v Madison*, 5 U.S. 137 (1803).

Respondents submit over 130 pages of briefing that quickly delve into the intricate and nuanced history of BLM's waste prevention authority.[1] Petitioners, however, do not dispute BLM has statutory authority to manage waste and do not ask the Court to define the precise limits of such authority. Petitioners simply petition the Court to do what the United States Constitution requires: recognize that Congress has not authorized BLM to promulgate the Rule.

Respondents repeatedly attempt to obfuscate Petitioners' straightforward assertion that BLM has acted without authority in promulgating a comprehensive air quality regulatory scheme. For example, Respondents devote large portions of their briefs to BLM's ability to manage public lands in a way that limits impacts to air quality. But Petitioners do not argue BLM may never take discrete local or regional actions aimed at reducing impacts to air quality through individual land management plans.[2] The sweeping breadth of the Rule, which impacts every oil and natural gas facility on federal and Indian leases, cannot be compared to such limited actions.

Similarly, the Rule does not merely "update," "amend," or "refine" NTL-4A, as BLM claims. NTL-4A was six-pages long and addressed three issues: (1) defined avoidably lost gas subject to royalties; (2) authorized venting and flaring on a case-by-case basis; and (3) defined

[1] *See Citizen Groups' Resp. to Mots. for Prelim. Inj.*, Docket No. 69 (hereinafter "Cit.Grps."); *Federal Resp'ts' Consolidated Opposition to Pets.' and Pet.-Intervenor's Mots. for Prelim. Inj.*, Docket No. 70 (hereinafter "Govt."); *State Resp'ts' Opposition to Pet.-States' Mots. for Prelim. Inj.*, Docket No. 77 (hereinafter "CA/NM").

[2] *See generally* Petitioners' *Memorandum in Support of Mot. for Prelim. Inj.*, 16-CV-280, Docket No. 13 ("Pets.").

beneficial use of oil and gas not subject to royalty. On its face the Rule comprises 11 pages of single-spaced codifications spanning two parts and two more subparts of the Federal Register. It is preceded by nearly 70 pages of a highly-technical preamble. Substantively, the Rule changes longstanding concepts governing avoidable and unavoidable waste, and royalty-bearing gas. It requires operators to develop and disclose detailed and complex waste minimization plans with highly confidential and proprietary information. It creates new compliance obligations, all of which carry the full force of federal sanctions, including fines, penalties, permit delays, and lease suspensions. The fatal flaw, however, is that, for the first time in the Department of the Interior's existence and without congressional authorization, the Rule imposes a comprehensive air quality regulatory scheme on all oil and gas facilities on federal and Indian leases. This scheme includes requirements to control emissions, inspect and replace equipment, and it extends to existing facilities, which the Environmental Protection Agency (EPA) itself has not even done. The near-silence in Respondents' briefs concerning the regulation of existing facilities and the conflicts this Rule poses with Section 111(d) of the Clean Air Act (CAA) is deafening.

Remarkably, Government Respondents argue the Rule contains no air quality provisions because "[i]t sets no emission standards for particular pollutants and contains no air quality monitoring requirements." Govt. at 2. This statement is plainly wrong. First, the Rule imposes emission standards for storage tanks (limiting emissions to six tons per year (tpy) of volatile organic compounds (VOCs)) and contains provisions for monitoring leaks. *See* AR 438-441 (43 C.F.R. §§ 3179.203, 3179.301-305). Second, emissions standards and monitoring requirements are not necessary conditions for controlling air pollution. *See* 42 U.S.C. §7411(h). Petitioners urge the Court to reject Government Respondents' narrow and simplistic characterization of an air quality regulation.

Respondents mischaracterize other justifications for the Rule. Most concerning among them is the oversimplification and dismissive tone regarding why flaring and venting occurs. BLM would have this Court believe it has a monopoly of wisdom on this point—which can be boiled down to operator laziness, greed, and negligence. *See e.g.*, Govt. at 4 ("operators often choose the easiest, and most wasteful, option: flaring") (emphasis added); *id*. at 38 ("Petitioners would have this Court believe that operators operate in a vacuum"); *id*. ("Operators are aware, or could easily make themselves aware, of when new wells come on line" and "can also plan their development in a way that ensures they have adequate infrastructure to capture produced gas before a new well is drilled"); *id*. at 44 (Petitioners "ignore the fact that operators choose when and where to drill their wells"); Cit.Grps. at 47 (referencing "inadequate infrastructure"). If only it were so easy.

The reality is that the production, gathering, and distribution of oil and natural gas is perhaps one of the most complex endeavors in the modern industrial age. There are numerous reasons operators must flare or vent, none of which owe to laziness, greed, or negligence. In fact, the 2010 Government Accountability Office (GAO) report BLM relies upon, itself, acknowledges at least 60 percent of gas flared cannot be technically or economically captured (i.e., it must be flared or vented). *See* AR 448 (RIA at 2); AR 2672 (U.S. Gov't Accountability Office, GAO-11-34, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases* (Oct. 2010)). BLM's attempt to paint such a complexity as black and white is misleading and ignores reality and its own data.[3]

[3] *See, e.g.*, AR 31727 (American Petroleum Institute (API) Comments at 41(April 22, 2016)) ("BLM in North Dakota has expressly acknowledged that in the Bakken it may be 'necessary to

Similarly, BLM belittles the legitimate economic and other irreparable harms Petitioners will suffer from the Rule, calling the Rule's costs "modest" and "ordinary." *See* Govt. at 63 ("Petitioners present no credible evidence of implementation costs but rather suggest that any amount is too much because the Rule is not legal") (emphasis added).[4] Citizen Groups similarly claim operators are concerned with "nothing more than the possibility of a very small diminution in [ ] profits." *See* Cit.Grps. at 34. These statements ignore ample evidence of the serious threats the Rule poses to hundreds of operators. *See infra* § IV; *see also* Pets. at §§ III-VI. This treatment incorrectly assumes all oil and natural gas companies are the same, operate on uniform economics, and can absorb significant capital costs and withstand forced well shut-ins and associated loss of lease rights. Petitioners provide the Court several declarations serving as concrete examples of the serious and immediate impacts facing operators under the Rule, and more importantly what these impacts portend for smaller operators and marginally economic wells. *See generally* Decl. of D. Naatz, attached as Exhibit 1 ("Naatz Suppl. Decl."); Decl. of J. Dunham, attached as Exhibit 2 ("Dunham Decl."); Decl. of C. Miller, attached as Exhibit 3 ("Miller Decl."); Decl. of J. Benton, attached as Exhibit 4 (Benton Decl.); Decl. of K. Sgamma, attached as Exhibit 5 ("Sgamma Suppl. Decl."); Decl. of D. Ballard, attached as Exhibit 6 ("Ballard Decl.") (collectively, Exhibits 1-6).

Finally, Respondents argue the Rule is lawful because BLM somehow has a unique interest in preventing waste of "public resources." *See, e.g.*, Govt. at 2; CA/NM at 6

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burn or release gas for a number of operational reasons, including lowering pressure to ensure safety.'") (emphasis in original).

[4] It is hard to comprehend how BLM can claim Petitioners have presented "no credible evidence of implementation costs," when BLM itself estimates the Rule will cost, in the aggregate, between $100 and $279 million per year, depending on the discount rate used. AR 450 (RIA at 4). BLM also estimates that the Rule will impose costs between $42,300 and $65,800 per operator. AR 575 (RIA at 129).

(describing BLM's charge to protect "the public welfare"). But the duty to prevent waste is fundamental to all oil and gas development, whether on federal and Indian leases or not, and mechanisms to conserve mineral resources have been in place since the early 20th century. Most states have developed a dual regulatory scheme, where the state oil and gas commission regulates waste and another regulatory body, typically the environmental department, regulates air quality. Two examples are Wyoming and its neighbor Colorado.[5] In both states, "flaring" has been carved out as the exclusive province of the oil and gas commissions, and they regulate this activity independently of the health/environmental departments. On the flip side, regulation of air quality is treated as the exclusive province of the health/environmental departments. In neither case has the state commission attempted to extend its waste prevention authority to air quality regulation or vice versa. Oil and gas commissions do not possess the requisite expertise to administer highly technical air quality regulatory schemes. The same is true for BLM. Like state environmental departments, EPA has the expertise to administer air quality, not BLM. The Court should not be persuaded of the Rule's legality simply because BLM considers itself the expert technical agency for all matters oil and natural gas. Ultimately, nothing in Respondents' briefs alters the fact that the Rule is an unlawful, unconstitutional and unreasonable exercise of BLM's statutory authority. Petitioners have demonstrated all four elements necessary for this Court to issue a preliminary injunction and Respondents have not shown otherwise. Pets. §§ III-VI.

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[5] *See* Wyo. Stat. Ann. § 30-5-102 (charging Wyoming Oil and Gas Conservation Commission with the prevention of waste); Colo. Rev. Stat. § 34-60-102(1)(a)(II), 34-60-107 (charging Colorado Oil and Gas Conservation Commission with the prevention of waste); Wyo. Stat. Ann. § 35-11-105 (charging Wyoming Department of Environmental Quality with protection of air quality); Colo. Rev. Stat. § 25-7-104 (creating air quality control commission).

II. LIKELIHOOD OF SUCCESS ON THE MERITS

Petitioners are likely to succeed on the merits of their petition because the Rule cannot survive judicial review. *See Olenhouse v. Commodity Credit Corp.*, 42 F.3d 1560, 1574 (10th Cir. 1994). Nothing in Respondents' briefs fixes the fact that this Rule fails all three *Olenhouse* determinations. *See generally* Pets. at 8-46. BLM does not have authority to promulgate the Rule and, even if it did, BLM did not comply with the Administrative Procedure Act (APA).

A. BLM Does Not Have Authority to Enact Comprehensive Air Quality Regulations

1. BLM Does Not Interpret a Statutory Ambiguity Implicating an Analysis under *Chevron*.

Respondents incorrectly argue BLM's interpretation of its authority to promulgate the Rule is entitled to deference under *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984). *See* Govt. at 13; Cit.Grps. at 9-16. Only where a case involves an agency's assertion of authority to regulate a particular activity under a statute it administers, must courts engage in the two-step inquiry adopted by the Supreme Court in *Chevron*. *See City of Arlington v. FCC*, 133 S.Ct. 1863, 1868 (2013) ("Congress, when it <u>left ambiguity in a statute</u> administered by an agency, understood that the ambiguity would be resolved . . . by the agency, and desired the agency . . . to possess <u>whatever degree of discretion the ambiguity allows</u>[.]") (emphases added) (citation and quotations omitted). For example, *Chevron* itself was about EPA's construction of one discrete term under the CAA—what constitutes a stationary source. 467 U.S. at 839-40, 866.

This Court need not reach the two-step analysis adopted in *Chevron* because Congress left no statutory ambiguity for BLM to resolve; BLM does not seek to resolve a specific statutory ambiguity with this Rule. Rather, BLM attempts to stitch together passing statements in <u>seven</u> different statutes to assert broad new regulatory powers over matters outside BLM's substantive

area of expertise.[6] Respondents argue BLM is the proper authority to construe these various statutes and assert the Court must afford BLM deference in the process. Govt. at 13-25; Cit.Grps. at 10. This goes too far. *See Marbury v. Madison*, 5 U.S. 137, 176 (1803) (it is the province of the courts to construe and determine the constitutionality of laws). Because *Chevron* and its progeny do not stand for the proposition that an agency's claim of authority based on a patchwork of statutes is entitled to deference, the Court may rule, without deference to BLM, that the Rule exceeds BLM's statutory authority.

2. Even if *Chevron* Applies, BLM Had No Authority to Promulgate the Rule and its Construction Receives No Deference.

Even if the Court applies *Chevron's* framework to its analysis of the Rule, Congress did not delegate authority to BLM to establish a comprehensive air quality regulatory regime with its land management or waste prevention authorities. When determining whether an agency acted within its scope of authority, the Court must first delineate the agency's scope of authority and discretion, and then consider "whether on the facts, the agency's action can reasonably be said to be within that range." *Olenhouse*, 42 F.3d at 1574. An administrative agency "may not exercise its authority 'in a manner that is inconsistent with the administrative structure that Congress enacted into law,'" and the Court must give effect to Congress' intent. *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 125 (2000) (citation omitted); *see also Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988). Critically, even when it comes to agency jurisdiction, an agency's discretion and the delegation of general authority to promulgate

[6] *See* AR 371 (81 Fed. Reg. at 83019) (citing legal authority from MLA, 30 U.S.C. §§188-287, Mineral Leasing Act for Acquired Lands, 30 U.S.C. §§ 351-360, Federal Oil and Gas Royalty Management Act, 30 U.S.C. §§ 1701-1758; Federal Land Policy and Management Act of 1976, 43 U.S.C. §§ 1701-1785; Indian Mineral Leasing Act of 1938, 25 U.S.C. §§ 396a-g; Indian Mineral Development Act of 1982, 25 U.S.C. §§ 2101-2108; and Act of March 3, 1909, 25 U.S.C. § 396).

regulations only extends to matters "within the agency's substantive field." *See City of Arlington*, 133 S. Ct. at 1874. Here, Congress directly addressed the issue of whether any other federal agency except EPA has authority to comprehensively regulate air quality, and the answer is no. *See* Pets. at 9-26.

The Government Respondents maintain "[t]he 'question in every case is, simply, whether the statutory text forecloses the agency's assertion of authority.'" Govt. at 13 (citing *City of Arlington*, 133 S. Ct. at 1871). Yet the law is well established an agency cannot act simply because Congress has not expressly prohibited the agency from taking such action. *See Chamber of Commerce of U.S. v. NLRB*, 721 F.3d 152, 160 (4th Cir. 2013) (a court "[cannot] presume a delegation of power [to an agency] simply from the absence of an express withholding of power[.]"). Congress did not delegate authority to BLM to substantively regulate air quality on public lands—it specifically tasked EPA with that responsibility. Simply because the seven statutes may not address the issue of air quality regulation does not equate to permission. *Id.* Congress knows how to grant authority, and it does not do so by "hid[ing] elephants in mouseholes." *Whitman v. Am. Trucking Ass*, 531 U.S. 457, 468 (2001). It is irrational to interpret the general authority granted to BLM under a smattering of waste prevention and land use management statutes as providing the requisite authority to establish a comprehensive air quality rule. Thus, either under or outside of *Chevron*, the Rule is unlawful.

3. Respondents Ask this Court to Ignore the Rule's Central Comprehensive Air Quality Regulatory Scheme.

Respondents characterize the Rule as a logical extension of BLM's longstanding waste prevention authority and necessary to update NTL-4A to "ensure the proper payment" of

royalties.[7] *See* Govt. at 72 (characterizing the Rule's air quality effects as "incidental"); *see also* CA/NM at 1 (describing the Rule as a "commonsense rulemaking"); *id.* at 8 ("the Rule may also have benefits for air quality"). Such portrayals are belied by the Rule's text, structure, and impact. Moreover, these characterizations ignore the Rule's direct outgrowth of the White House's March 2014 Climate Action Plan and the administration's methane reduction plan to address climate change.

Government Respondents list ten core provisions from the Rule and characterize each as waste management efforts. Govt. at 19. Six of the ten provisions, however, in nomenclature and effect directly regulate air emissions and air quality, including: (1) the prohibition on venting; (2) replacement requirements for pneumatic controllers; (3) the Leak Detection and Repair (LDAR) program; (4) control requirements for storage vessels; (5) placing limits on emissions volumes during well completions and initial production testing; and (6) requiring waste minimization plans to reduce flaring. The first five are substantive air quality control requirements, and numbers two through five are taken directly from EPA air control requirements under New Sours Performance Standards (NSPS) OOOO and OOOOa. *See* 40 C.F.R. §§ 60.5390, 60.5390a, 60.5397a, 60.5395, 60.5395a, 60.5375, 60.5375a. If the Rule is truly just a reasonable refinement of NTL-4A that happens to produce "incidental" air quality co-benefits, it begs the question why BLM needed to convene over 40 conference calls with EPA staff prior to issuing the Rule. Govt. at 8. Petitioners urge the Court not to give credence to these semantics, and instead to look at the Rule's effect.

[7] Government Respondents claim "[t]he text and structure of the Rule, combined with BLM's longstanding history of regulating venting and flaring demonstrate that the Rule is a waste prevention regulation, not an air quality regulation[.]" Govt. at 18-19. This statement suggests the Court should ignore the substance and impact of agency action, which is incorrect.

Moreover, Government Respondents claim this Rule is a waste prevention regulation because it does not impose emission standards or limits for particular pollutants. *See* Govt. at 20 (arguing it is "clear" the Rule's "primary purpose is to prevent waste" because it "does not contain emissions limits for particular pollutants" or "require that operators measure particulate matter, such as PM 2.5, or other common air pollutants"); *see also* CA/NM at 10 ("the Rule does not set new source emission standards"). This claim is incorrect in two respects.

First, the Rule does regulate emissions. Section 3179.203 requires operators control emissions from storage vessels if they have the potential for VOC emissions equal to or greater than six tpy. On its face this is an emission limit for VOCs from storage vessels. Furthermore, the storage vessel provision is modeled directly upon emissions standards under EPA's NSPS OOOO and OOOOa, as well as several state air quality regulations (e.g., Colorado and Wyoming). Additionally, in BLM's own words, the LDAR requirements under Sections 3179.301–305 "establish[] a fixed semiannual schedule for <u>monitoring</u> leaks," AR 370 (81 Fed. Reg. at 83,018) (emphasis added), and "[f]inal section 3179.302 also allows any person to request and BLM to approve the use of an alternative <u>monitoring</u> device, accompanied by a <u>monitoring</u> protocol." AR 379 (81 Fed. Reg. at 83,027) (emphases added).

Second, emissions limits do not necessarily define an air quality regulation. A central provision of the CAA, Section 111, provides for air pollution control under a variety of means, including work practice and operational standards. *See* 42 U.S.C. § 7411(h) ("if in the judgment of [EPA], it is not feasible to prescribe or enforce a standard of performance, [EPA] may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof"). In fact, many of the oil and gas air quality regulations promulgated by EPA under Section 111 are work practice or operational standards (e.g., LDAR). If Government

Respondents were correct on this point, Petitioners expect EPA would be surprised to learn virtually none of its recent oil- and- gas-related regulations actually control air pollution.

4. The Rule Conflicts with EPAs Authority.

The Rule conflicts with the CAA authority delegated to EPA, states, and tribes, and it erodes the act's cooperative federalism framework. *See generally* Pets. at 10-20. The Rule also tramples on the narrowly-tailored approach Congress requires EPA take when regulating air emissions from oil and gas sources. *Id*. For example, in its response, BLM asserts the majority of flaring on BLM-administered leases is the result of "new well construction." Govt. at 6 (emphasis added). If that is the case, the Rule need not extend so broadly to all existing sources. BLM's assertion illuminates why the Rule is reckless and not narrowly tailored to address the specific problem (i.e., new well construction). It also demonstrates how the Rule conflicts with the CAA by regulating existing sources before EPA does and without adhering to the narrow requirements and procedure under section 111(d) of the CAA. *See* 42 U.S.C. §7411(d).

Respondents characterize the Rule as merely permissible agency "overlap." *See* Govt. at 27-28; CA/NM at 10. Petitioners do not dispute statutory and regulatory overlap can and does occur. Respondents ignore, however, that to take any action an agency must act within the scope of its authority and must exercise such authority reasonably. Without satisfying these fundamental requirements, cooperative and overlapping agency obligations cannot, by definition, exist. One agency may not simply wander into the jurisdiction of another without express and specific congressional authority.

The case law upon which Respondents rely to justify this overlap is not relevant here. The Supreme Court in *Massachusetts v. EPA* determined one term, "air pollutant," under one statute, the CAA, unambiguously authorized EPA to regulate carbon dioxide and other

greenhouse gas (GHG) emissions from new motor vehicles following an endangerment finding. 549 U.S. 497, 528 (2007). The Court found the "wholly independent" statutory obligations of each agency—the Department of Transportation (DOT) to promote energy efficiency through mileage standards and EPA to protect public health—capable of being coordinated on the very narrow issue of GHG emissions from vehicle tailpipes. *Id*. at 532. In contrast to this case, the Court implicitly recognized DOT and EPA had clear, independent regulatory authority in the first instance. The issue simply was whether this independent statutory authority was capable of coordination. Unlike BLM here, EPA was not requesting the Court find new authority or expand its existing regulatory powers; in fact, EPA requested narrower statutory authority than the Court ultimately found. The holding in *Massachusetts* was also limited in effect—to the extent EPA went on to regulate GHGs from motor vehicles following an endangerment finding, it had to coordinate with DOT mileage standards to ensure consistency.

This is a much different case. BLM asks this Court to construe numerous provisions of seven different statutes to assert new and expansive regulatory authority. The effect of BLM's request would be the judicial authorization of sweeping new statutory powers. A similar framework and request may well have resulted in a different outcome in *Massachusetts*. A finding in BLM's favor would upend the regulation of the entire oil and natural gas industry, substituting BLM for the EPA in many significant ways related to air quality control—not the least of which being BLM's regulation of existing facilities before EPA has even tried to do so. *See e.g.* AR 389 (81 Fed. Reg. at 83,037). This cannot be what the *Massachusetts* Court meant when it said two agencies, in theory, can "administer their obligations and yet avoid inconsistency." 549 U.S. at 532. Moreover, Congress did not intend this result when it directed

BLM to "provide for compliance with applicable" air pollution standards in FLPMA. *See* 43 U.S.C. § 1712(a)(8).

Citizen Groups argue *POM Wonderful LLC v. Coca-Cola Company*, 134 S. Ct. 2228, 2236 (2014), is directly on point. *See* Cit.Grps. at 21-22. *POM Wonderful* is inapplicable. In *POM Wonderful*, the Supreme Court considered "whether a private party may bring a Lanham Act claim challenging a food label that is regulated by the [Federal Drug and Cosmetic Act]." 134 S. Ct. at 2236. *POM Wonderful* is inapplicable because the present inquiry is not whether a <u>private</u> party may bring a limited cause of action under one statute or another. Rather, the dispositive issue in this case is the existence and scope of a <u>federal agency's</u> statutory authority.

1. The Patchwork of Statutes BLM Cites Do Not Give it Authority to Comprehensively Regulate Air Quality.

The Federal Oil & Gas Royalty Management Act (FOGRMA), Indian Mineral Leasing Act (IMLA), FLPMA, MLA and other sources cited by Respondents do not confer on BLM the authority to regulate air quality, for the reasons outlined in Petitioners' Brief. *See generally* Pets. at 21-26. Government Respondents maintain FLPMA allows BLM to manage public lands to protect air quality, pointing to air quality mitigation measures within BLM resource management plans (RMPs). *See* Govt. at 28. These measures reinforce BLM's limited authority to manage air quality. *See* AR 389 (81 Fed. Reg. at 83,037). Petitioners do not dispute BLM adopts air quality management measures in RMPs pursuant to its land use planning authority. *See* 43 U.S.C. § 1712(e); *Amigos Bravos v. BLM*, Nos. 6:09-cv-00037-RB-LFG, 6:09-cv-00414-RB-LFG, 2011 WL 7701433 (D.N.M. Aug 3, 2011). These management measures, however, are specific to the localized resources, developed in consultation and coordination with state air quality agencies,

and are not nationwide standards.[8] In fact, localized air quality management is appropriate and consistent with the cooperative federalism structure of the CAA.

Respondents similarly place too much weight on FLPMA's direction that BLM "take any action necessary to prevent unnecessary or undue degradation" of the public lands. 43 U.S.C. § 1732(b); *see* Govt. at 24; Cit.Grps. at 25; CA/NM at 7. BLM has not determined the Rule is "necessary" to prevent unnecessary or undue degradation of the public lands. *See generally* AR 361-366 (81 Fed. Reg. at 83,009-83,015). Furthermore, BLM has never relied on this rulemaking authority to enact such a sweeping rule that affects a principal or major use of the public lands. *See* 43 U.S.C. § 1702(l). Moreover, this Rule marks BLM's first assertion of such authority; BLM has consistently characterized its land management authority as distinct from EPA's authority to regulate air quality.[9] None of the cases cited by Respondents stand for the notion that BLM's ability to prevent "unnecessary or undue degradation" confers broad air quality

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[8] BLM's air quality management measures have faced objections that they exceed the agency's authority. *See, e.g.*, BLM Approved RMP & Record of Decision for Public Lands Administered by the Tres Rios Field Office, Dolores, Colorado App. S, S-23 (2015), available at https://www.blm.gov/co/st/en/fo/sjplc/land_use_planning.html (citing public comment requesting BLM and Forest Service "clarify the limits of their authority over visibility impacts under the [CAA] to acknowledge that they cannot regulate oil and gas facilities' emissions").

[9] *See* BLM Air Resource Management Program Strategy 2015–2020 (2015), available at https://www.blm.gov/style/medialib/blm/wo/Planning_and_Renewable_Resources/soilwaterair/swa_shared.Par.45752.File.dat/AirResourceProgramStrategy_2015to2020.pdf (observing BLM and EPA "have distinct roles and responsibilities under the legal framework governing air resource management"); Memorandum of Understanding Among the U.S. Dep't of Agric., U.S. Dep't of the Interior, and U.S. Envtl. Prot. Agency, Regarding Air Quality Analysis and Mitigation for Federal Oil and Gas Decisions through the National Environmental Policy Act (June 23, 2011) (describing BLM's authority over air quality as limited to developing land use plans and providing for compliance with state and pollution control laws), available at http://www.doi.gov/news/pressreleases/upload/29704-Joint-MOU-Air-Quality-FINAL.pdf.

regulatory authority.[10] *See id.* FLPMA does not allow BLM to issue the Rule, and Respondents offer no justification to the contrary.[11]

B. Even Under BLM's Statutory Authority to Regulate Waste and Manage Federal Land, the Rule is not Reasonable, and it is Procedurally Deficient, Arbitrary, and Capricious.

Although this Court should not afford BLM any deference in its construction of the land management statutes for the reasons outlined above, even if it does, Petitioners have shown the Rule still must be set aside. *See generally* Pets. at §§ III-VI.

1. The Rule Does Not Reasonably Construe BLM's Authority under MLA to Manage Waste.

The Rule impermissibly construes BLM's waste management authority for the reasons cited in Petitioners brief.[12] *See* Pets. at Section III(B)-(D). Government Respondents argue the

[10] Government Respondents mischaracterize the Interior Board of Land Appeals' decision *Coalition for Responsible Mammoth Development*, 187 IBLA 141 (2016), as holding "for purposes of § 1712(c)(8) that BLM may assume federal and state enforcement of air quality regulations for NEPA purposes." *See* Govt. at 25. In this decision, the IBLA recognized states—not BLM—through the CAA enforce air quality standards, and BLM may rely on enforcement of air quality standards by these agencies in its NEPA decisions. *See* 187 IBLA at 231 (holding BLM "does not itself enforce the requirements of the CAA" but must ensure compliance in executing its NEPA authority).

[11] Citizen Groups observe BLM regulates emissions of hydrogen sulfide from oil and gas operations. *See* Cit.Grps. at 25 (citing BLM Onshore Order No. 6, 55 Fed. Reg. 48,958 (Nov. 23, 1990)). Onshore Order No. 6 is not analogous to the Rule. BLM did not issue Onshore Order 6 under the guise of its land management authority under FLPMA. *See* 55 Fed. Reg. at 48,968. Moreover, Onshore Order 6 has a narrow purpose to "protect public health and safety and those personnel essential to maintaining control of the well." *Id.*

[12] The Citizen Groups argue BLM's interpretation of its own regulation deserves deference. *See* Cit.Grps. at 11-12. Under *Auer v. Robbins*, 519 U.S. 452, 461 (1997), a court must defer to an agency's interpretation of its own regulation unless "plainly erroneous or inconsistent with the regulation." At issue in *Auer* and similar cases, however, are agencies' administrative interpretations of their regulations. *See id.* at 454-55 (challenging employee's salary status); *Gonzales v. Oregon*, 546 U.S. 243, 255 (2006) ("An <u>administrative rule</u> may receive substantial deference if it interprets the issuing agency's own ambiguous regulation") (emphasis added). BLM is plainly interpreting statutory authorities, not a regulation. Citizen Groups offer the tortured rationale that BLM's definition of "avoidably lost" is entitled to *Auer* deference because

Rule's definition and treatment of "unavoidably lost" gas is reasonable "[b]ecause the Rule maintains the distinction between avoidably and unavoidably lost gas[.]" Govt. at 42. Their argument elevates form over substance. The Rule unreasonably narrows unavoidably lost gas to only twelve circumstances, entirely removing the flexibility and case-by-case analysis that has governed since 1979. Pets. at 29-30. Further, these new categories do not cover "all truly unavoidable situations," such as maintenance events on gathering systems and do not make the rules "easier for operators to follow." Govt. at 37; *see* Miller Decl. ¶ 14. In these respects, the Rule's definition of "unavoidably lost" is actually inconsistent with the concept of "waste" under the MLA. Pets. at 30-31.

Likewise, Government Respondents offer no meaningful response to Petitioners' assertion the Rule increases rather than decreases waste. Although Government Respondents assert Petitioners present "no evidence whatsoever" to show operators may be forced to shut-in or abandon wells rather than comply with the Rule, *see* Govt. at 39, the reality is the Government Respondents simply do not accept Petitioners' repeated assertions that the Rule will cause wells to be shut in or abandoned. *See* Pets. at 32-33; Miller Decl. ¶¶ 18-20; Benton Decl. ¶ 10; Dunham Decl. ¶¶ 6-7; Naatz Supp. Decl. ¶¶ 6-10; Sgamma Supp. Decl. ¶¶ 4-8. Instead, the Government breezily claims, without any support, that operators can simply increase pipeline capacity and other infrastructure if and where they want. *See* Govt. at 3 (flaring "is often done because <u>operators and midstream companies</u> have not built the infrastructure needed to capture produced gas.") (emphasis added). Evidence shows lack of pipeline capacity is beyond operators' control and flaring must occur for many reasons, including <u>safety</u>. *See* State Director Review No. 922-15-07 (Feb. 11, 2016), attached hereto as <u>Exhibit 7</u>, at 7 (recognizing lack of

BLM introduced this term in the Rule and NTL-4A. Because the definition of "avoidably lost" is set forth in a formal rule rather than administrative rule, *Auer* is inapplicable.

pipeline capacity is beyond operator's control and flaring is inevitable) (referenced in API Comments and NDPC Comments); *id.* at 11 (recognizing BLM and other federal agencies are responsible for pipeline delays, and discussing challenges associated with building pipelines); AR 31727 (API Comments at 46) ("The BLM in North Dakota has expressly acknowledged that in the Bakken it may be 'necessary to burn or release gas for a number of operational reasons, including lowering pressure to ensure safety.'") (emphasis in original). Government Respondents err by claiming simple solutions exist to the Rule's complex problems.

Government Respondents also claim "the final rule will dramatically reduce the large number of requests for approval to flare royalty-free that operators have had to file and the BLM has had to process[.]" Govt. at 34. To justify this statement Government Respondents rely, in part, on various exemptions and alternative flaring options available through sundries in the Rule. Government Respondents irrationally fail to acknowledge exemption requests and premature abandonment applications filed by operators will increase in the wake of this Rule, likely offsetting any reductions in flare requests. *See* AR 31719 (API Comments at 38) ("With the large increase in the number of Sundry Notice submittals and requirements for approval by BLM . . . API is concerned that BLM will not be able to review and respond in a reasonable amount of time to requests for royalty-free treatment [] under § 3178.9); AR 31833 (API Comments at 111) (noting that BLM generally underestimates the burden to operators and the agency for all sundry notices).

Finally, Respondents incorrectly argue non-federal parties to unit agreements and communitization agreements contractually agreed to the Secretary's regulation of all oil and gas operations, including nonfederal and non-Indian wells. Govt. at 46, 48; Cit.Grps. at 28. BLM's authority to regulate the "quantity and rate of production" federal units cannot be equated to a

power to limit venting, flaring, or waste or to impose air quality controls. *See* 43 C.F.R. § 3186.1 ¶ 21; *accord* 30 USC § 226(m). Indeed, a federal lease treats the lessee's obligation to prevent waste as distinct from the lessor's ability to specify the "rate" of production. *See* BLM Form 3110-11, Offer to Lease and Lease for Oil and Gas (2008) § 4.[13] Accordingly, BLM's contractual right to regulate "quantity and rate of production" is just that—the authority to oversee the amount and pace of production. Similarly, the Secretary's "right of supervision" over fee and state mineral operations within a communitized area cannot be reasonably construed as an unfettered right to regulate development. Noticeably, federal unit and communitization agreements do not include a provision akin to the language in a federal lease that "[r]ights granted are subject to. . . regulations. . . hereinafter promulgated when not inconsistent with lease rights granted." BLM Form 3110-11, *supra*. Parties to unit and communitization agreements did not consent to the BLM's regulatory authority over nonfederal and non-Indian wells.

2. The Rule Lacks Justification under the APA.

BLM failed to base the Rule on substantial evidence on the record as required by the APA. *See generally* Pets. at 39-44. Respondents' briefs do not cure this defect. Among other things, the Rule fails to identify the problem it seeks to solve or how it actually solves anything.

First, Government Respondents cite misleading data by claiming that venting and flaring is increasing rapidly. *See* Govt. at 52 ("BLM considered data showing that the quantities of vented and flared gas was increasing exponentially. . . studies indicating that more natural gas is lost through leaks and unreported venting than previously understood."). In fact, venting and flaring is decreasing on a per well basis while overall production is increasing. Pets. at 41 n. 34.

[13] Available at https://www.blm.gov/style/medialib/blm/noc/business/eforms.Par.71287.File.dat/3100-011.pdf.

Leak rates are well below one percent on most sites. *See* AR 3502-09. [14] Additionally, a recent National Oceanic and Atmospheric Administration (NOAA) study found that globally, methane emissions from the fossil fuel industry are actually down despite large production increases.[15] *See* AR 17515-16.

Second, in terms of royalty value, Government Respondents criticize Petitioners' point that the Rule only reduces *de minimis* waste volumes by attacking Petitioners' underlying data. *See* Govt. at 52 n.18 (arguing Petitioners rely on "outdated and arguably incomplete" data). However, Petitioners based their expected royalty value calculation on the data BLM itself offers in the RIA. *See* AR 461 (RIA at 15). The issue is not whether the Rule is too expensive, but rather that the Rule has a *de minimis* impact—which it does when viewed in this light. Accordingly, the Rule cannot be justified as a waste prevention measure under the APA.

Third, BLM estimates the Rule is expected to deliver a 35 percent reduction in total volume of venting and a 49 percent reduction in flaring. *See* Govt. at 9-10 (citing AR 451, 455 (RIA at 5, 9)); CA/NM at 4. However, BLM entirely ignores the most recent June 2016 GAO report, which demonstrated severe limitations and problems in BLM's flaring and venting data, and ultimately concluded BLM "does not have the information it needs" to assess the extent of flaring and venting or ensure it is minimizing waste. AR 19894 (Gov't Accountability Office, GAO-16-607, *Oil and Gas Leasing: Interior Could Do More to Account for and Manage*

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[14] *See also* Allen, David T., *et al.*, "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings," Environ. Sci. Technol. (2015), 49 (1), pp 641-48 (available at http://pubs.acs.org/doi/abs/10.1021/es504016r).

[15] The lead scientist for the NOAA study also characterized methane from oil and gas as "not directly responsible for the increase in total [global] methane emissions observed since 2007." http://www.noaa.gov/media-release/study-finds-fossil-fuel-methane-emissions-greater-than-previously-estimated

Natural Gas Emissions, 14 (July 2016)). To justify this Rule in a "waste prevention" context on such uncertain and inaccurate data is arbitrary and capricious.

Finally, the cost benefit analysis and related conclusions are arbitrary. *See generally* RIA. Respondents repeatedly argue the Rule is justified because it reduces waste and only has incidental effects on air quality. Respondents also argue Petitioners fail to acknowledge the environmental and social benefits of the Rule. Govt. at 52-53; Cit.Grps. at 2. However, the only way the costs justify this Rule is through its purported air quality benefits as measured by the social cost of methane (SCM), Pets. at 46; Dunham Decl. ¶ 16. This justification, which is the <u>only</u> way BLM can get benefits to exceed costs is improper and renders the rule arbitrary and capricious.

Predictably, Citizen Groups urge the Court to consider the recent opinion in *Zero Zone, Inc. v. Department of Energy*, 832 F.3d 654 (7th Cir. 2016), when evaluating the Rule's benefits. *Zero Zone* is not relevant here and does not support BLM's novel use of the social cost of methane to justify this Rule. At issue in *Zero Zone* was a Department of Energy rule promulgated under the Energy Policy and Conservation Act (EPCA), as amended, to improve the energy efficiency of commercial refrigerators. The 2005 amendments to EPCA included provisions with a global reach. *See e,g.*, Pub. L. No. 109-58, § 985, 119 Stat. 909 (codified at 42 U.S.C. § 16341(b)(3)) (providing for assistance "in the development and transfer of energy supply and efficiency technologies that would have a beneficial impact on world energy markets"). In contrast, the statutes at issue here, including the CAA, only authorize the regulation of domestic activity. Thus, the statutory framework at issue in *Zero Zone* is entirely different. Moreover, the commodities at issue in *Zero Zone*—commercial refrigerators—reach global markets. Thus, it was arguably relevant to consider global climate change impacts in that

context. Here, the only way the Rule's benefits outweigh its costs is through an evaluation of global benefits. BLM did not consider domestic benefits at all. *See* AR 452 (RIA at 6).

Moreover, the cost benefit analysis does not address the cost of the Rule on a per-well basis. The analysis focuses on the per entity cost. *See* AR 575-76 (RIA at 129-30). This omission is arbitrary and makes it impossible for BLM to evaluate the actual impact of the Rule. *See* Dunham Decl. ¶¶ 10-12. For example, the Rule will impact smaller operators much differently than larger operators. Miller Decl. ¶¶ 11, 17-19; Benton Decl. ¶ 10; Ballard Decl. ¶ 7; Dunham Decl. ¶¶ 10-14. Even a small uptick in monthly costs on marginally economic wells can force a small operator to shut-in a well. Miller Decl. ¶ 19; Dunham Decl. ¶¶ 10-14; Sgamma Supp. Decl. ¶ 8. And the Rule affects thousands of marginally economic wells. These flaws in the economic assessment demonstrate BLM has not articulated a rational connection between the facts found and the choices made, and lacks a reasoned basis for the Rule. *See Olenhouse*, 42 F.2d at 1575.

III. PETITIONERS DEMONSTRATE LIKELIHOOD OF IRREPARABLE HARM

Petitioners have met their burden of establishing "that irreparable injury is likely in the absence of an injunction." *Winter v. Natural Res. Def. Council, Inc.*, 555 U.S. 7, 22 (2008) (emphasis in original). Petitioners demonstrate "a significant risk" their members "will experience harm that cannot be compensated after the fact by monetary damages." *RoDa Drilling Co. v. Siegal*, 552 F. 3d 1203, 1210 (10th Cir. 2009) (citation omitted) (emphasis added).[16] Specifically, Petitioners demonstrate application of the Rule will: (1) impose compliance costs that cannot be recovered because of the United States' sovereign immunity; (2) require disclosure of proprietary and confidential information; and (3) require payment of additional royalties on gas BLM now characterizes as "avoidably lost." Contrary to

[16] Respondents claim Petitioners must wait for the Rule's implementation to know they will suffer harm. Govt. at 39 n. 12. This is contrary to well-established law. *Winter*, 555 U.S. at 31.

Respondents' claims, these types of irreparable harm are precisely the kinds of injuries preliminary injunctions are meant to address. Likewise, this harm is not "speculative," "unsupported" or "modest." *See generally* Exhibits 1-6.

A. The Compliance Costs Constitute Irreparable Harm Petitioners' Members are Likely to Suffer Absent an Injunction.

Respondents argue the compliance costs Petitioners' members will incur after the Rule becomes effective do not justify a preliminary injunction, and assert the harm likely to occur is not irreparable. Govt. at 65-67; Cit.Grps. at 32-35; CA/NM at 12-15. These assertions are simply wrong, and the supporting authority is selectively cited, taken out of context, or outdated. For example, Respondents cite several cases for the proposition that compliance costs are insufficient to constitute irreparable harm. Respondents ignore that compliance costs in these cases were compensable by monetary or other corrective relief at a later date. *See Heideman v. S. Salt Lake City*, 348 F.3d 1182, 1189 (10th Cir. 2003) ("It is also well settled that simple economic loss usually does not, in and of itself, constitute irreparable harm [because] <u>such losses are compensable by monetary damages</u>.") (emphasis added) (citations omitted); *Sampson v. Murray*, 415 U.S. 61, 90 (1974) ("'Mere injuries [ ] in terms of money, time and energy necessarily expended in the absence of a stay, are not enough. <u>The possibility that adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation</u>, weighs heavily against a claim of irreparable harm.'") (citation omitted) (emphasis added); *Wisconsin Gas Co. v. F.E.R.C.*, 758 F.2d 669, 674 (D.C. Cir. 1985) (same); *Freedom Holdings, Inc. v. Spitzer*, 408 F.3d 112, 115 (2d Cir. 2005) (not addressing issues of sovereign immunity and resulting inability to recover costs at a later date); *Am. Hosp. Assn v. Harris*, 625 F.2d 1328, 1331 (7th Cir. 1980) (same). In contrast, because of sovereign immunity, Petitioners' members cannot recover costs incurred to comply with the Rule.

Similarly, Government Respondents' assertion that the court in *Chamber of Commerce v. Edmondson*, 594 F.3d 742 (10th Cir. 2010), "found irreparable harm not based on the specter of unrecoverable compliance costs" has no merit. Govt. at 67. The court plainly stated "[i]mposition of monetary damages that cannot later be recovered for reasons such as sovereign immunity constitutes irreparable injury." *Edmondson*, 596 F.3d at 770-71 (citations omitted). The court later repeated, "[i]f forced to comply with the [Act], the Chambers' members will face a significant risk of suffering financial harm [.] Yet, because Oklahoma and its officers are immune from suit for retrospective relief[,] these financial injuries cannot be remedied." *Id.* at 771 (emphases added) (citations omitted).

The Government Respondents also mislead the Court when stating: "Petitioners contend that because they will not be able to recover any potential compliance costs as damages, they need not prove that these losses are certain, great, actual, or imminent." Govt. at 66 (citing *Nat'l Mining Assn v. Jackson*, 768 F. Supp. 2d 34, 52 (D. D.C. 2011)). This is a mischaracterization of Petitioners' position. Petitioners have shown not only that the compliance costs here are unrecoverable due to sovereign immunity, but also that those costs are "certain, great, actual [and] imminent."[17] *Id.* Petitioners' members will suffer immediate, irreparable harm if the Rule takes effect on January 17, 2017. *See, e.g.*, Dunham Decl. ¶¶ 4-9; Miller Decl. ¶¶ 8-15 (discussing the immediate, irreparable effect of the Rule's royalty provisions), ¶¶ 16-19 (discussing the Rule's effect on marginally economic wells and resultant costs and impacts associated with shutting in such wells), ¶¶ 20-21 (discussing costs and impacts of record keeping and reporting requirements of the Rule), ¶¶ 22-23 (discussing resources expended for future drilling and the effect of being the Rule on these plans), ¶ 19 (estimating 28 percent of the

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[17] Nonetheless, even "to say that a harm is 'minimal' is not to say it is nonexistent." *Heideman*, 348 F.3d at 1190. *See generally* Exhibits 1-6.

company's wells may be shut-in due to the Rule). *See also* Benton Decl. ¶ 10 (estimating a cost of $3 million to comply in just one field); Ballard Decl. ¶ 7-8 (discussing delays and duplicative compliance obligations and enforcement risks).

BLM estimates the Rule will cost between $110 and $279 million per year, AR 450 (RIA at 4), and evidence in the record suggests BLM has significantly underestimated the costs of compliance. *See* Pets. at 50; *accord* Dunham Decl. ¶ 4-9. Although BLM's brief dismisses costs borne by operators as "modest," Govt. at 66, Petitioners' members disagree with this characterization. The majority of operators affected by this Rule are not multi-national oil conglomerates. Most operators cannot swiftly shift assets or mobilize expensive alternative capture technologies,[18] pressure midstream companies to expand capacity,[19] or afford to simply suspend or abandon leases rather than comply with the Rule. [20] Naatz Supp. Decl. ¶¶ 9-10; Sgamma Supp. Decl. ¶ 3; Miller Decl. ¶¶ 16-17. And of those industry members who are the archetypal major operators, this Rule is sure to cost them far in excess of the $42,300 to $65,800

[18] Miller Decl. ¶ 21 (discussing prohibitive cost and safety issues with mobile capture technology).

[19] BLM portrays coordinating with midstream companies as an easy task, *see, e.g.*, Govt. at 3, but the evidence and information available to BLM shows otherwise. *See* AR 33950-52 (North Dakota Petroleum Council Comments) *and* AR 31729-30 (API Comments). Also, the Rule only functions the way BLM says it will if BLM actually has the capacity and power to be the ultimate manager of giant, multi-faceted, complex production and gathering systems, with the ability to monitor and relieve capacity constraints in real-time and coordinate maintenance events and infrastructure limitations. *See, e.g.*, 43 C.F.R. § 3179.9.

[20] BLM asserts if operators cannot capture emissions, then operators can simply suspend their leases. Govt. at 6. BLM, however, has been criticized for its use of lease suspensions by at least one of the Citizens Groups, thus raising questions as to the availability of suspensions as a viable alternative to flaring. *See* The Wilderness Society, *Land Hoarders*: *How Stockpiling Leases is Costing Taxpayers* (2015), *available at* https://wilderness.org/sites/default/files/TWS%20Hoarders%20Report-web.pdf; Gov't Accountability Office, GAO-09-74, *Oil and Gas Leasing: Interior Could Do More to Encourage Diligent Development*, 4-7 (Oct. 2008).

BLM estimates because they operate many wells. *See id.*; *see also* AR 573, 575 (RIA at 127, 129); Dunham Decl. ¶ 10.

Respondents also suggest the phased-in approach of some of the Rule's provisions prevents Petitioners from claiming their members will suffer irreparable harm before the Court can rule on the merits of this case. Govt. at 39-40; CA/NM at 13. These statements are inaccurate and self-serving given the evidence on the record showing Petitioners' members must immediately begin to expend capital to come into compliance with the Rule, *see* Pets. at 49, and the fact that BLM itself acknowledges the "requirements to replace existing equipment would <u>necessitate immediate expenditures</u>." AR 450 (RIA at 4) (emphasis added); *see also* Miller Decl. ¶¶ 10-12; Benton Decl. ¶ 10. In short, the record and evidence in the attached declarations demonstrate ample, immediate and serious harm to Petitioners' members for which they cannot be compensated.

B. The Rule Risks Public Disclosure of Proprietary Information.

Section 3162.3-1 of the Rule requires operators submit natural gas waste minimization plans with APDs. In submitting waste minimization plans to BLM, the Rule requires operators to disclose commercially sensitive and proprietary information about anticipated production from a proposed well. Pets. at 50-52; AR 430 (43 C.F.R. § 3162.3-1(j)(5)(i)–(iv)); *see also* Spisak Decl. ¶ 36 (acknowledging the Rule "could result in operators submitting confidential business information [ ] to BLM"). These projections and data are highly confidential and valuable; operators go to great lengths to protect this type of information from outside disclosure or unnecessary internal dissemination. Miller Decl. ¶ 26; AR 31710 (API Comments at 29) (explaining the sensitive nature of this information). Nonetheless, BLM has stated it will disclose waste minimization plans to the public. AR 395 (81 Fed. Reg. at 83,043) (stating BLM will post

each waste minimization plan for public review, subject to any protections for confidential business information).

Disclosure of this type of sensitive information cannot be remedied after the fact with monetary damages, and therefore would constitute irreparable harm. *See* Pets. at 50-52; *see also Universal Engraving, Inc. v. Duarte*, 519 F. Supp. 2d 1140, 1148-49 (D. Kan. 2007) (holding threat of proprietary information disclosure may demonstrate irreparable harm); *FMC Corp. v. Taiwan Tainan Giant Indus. Co., Ltd.*, 730 F.2d 61, 63 (2nd Cir. 1984) ("A trade secret once lost is, of course, lost forever."); *Campbell Soup Co. v. ConAgra, Inc.*, 977 F.2d 86, 92 (3rd Cir. 1992) (threat of trade secret disclosure may establish immediate irreparable harm); *Estee Lauder Cos. Inc. v. Batra*, 430 F. Supp. 2d 158, 174 (S.D.N.Y. 2006) (Even where a trade secret has not yet been disclosed, irreparable harm may be found based upon a finding that trade secrets will be disclosed). Petitioners have demonstrated this injury "is of such imminence that there is a clear and present need for equitable relief." *Heideman*, 348 F.3d at 1189 (emphasis removed).

Government Respondents state "if [operators] indicate [to BLM] that the information is considered confidential, BLM will handle the information in accordance with applicable regulations in 43 CFR part 2." Govt. at 67. On the record, however, BLM refuses to confirm the information required in waste minimization plans is actually subject to any statutory protections, even though BLM knows what type of information it will require and can make this assessment. *See* AR 403 (81 Fed. Reg. at 83,051) (stating only that "BLM will handle the information in accordance with" its Freedom of Information Act regulations); *see also* Pets. at 51-52. BLM's refusal to affirmatively recognize information in waste minimization plans as confidential gives operators little comfort their information will be protected. The Rule, therefore, presents a significant risk that proprietary and confidential business information will be publicly disclosed,

and once disclosed the harm cannot be remedied. Thus, Petitioners have demonstrated a significant risk of irreparable harm supporting a preliminary injunction.

IV. EQUITIES AND PUBLIC INTEREST WEIGH IN FAVOR OF INJUNCTIVE RELIEF

The third and fourth preliminary injunction factors—the balance of the equities and the public interest—also weigh strongly in favor of injunctive relief. Government Respondents' argument that an injunction will cause BLM to "suffer substantial harm" is without merit. Govt. at 74. Respondents rely on the now-tired notion that this Rule is merely an update to NTL-4A. *See id.* (stating that "BLM is presently regulating oil and gas waste under a regime that is now 37 years old"); *see also* CA/NM at 3-4 (arguing the Rule is necessary for BLM to revise its "insufficient and outdated" waste and royalty regulations). Such logic suggests an absurd outcome: a court should refrain from enjoining agency action lest the agency be stuck with its outdated regulatory scheme. BLM had the opportunity to lawfully update NTL-4A for 30 years. Tellingly, BLM has only now strayed beyond the confines of its statutory authority in the wake of the White House's directives on climate change. The balance of the equities and the public interest weigh in favor of enjoining such action to preserve the status quo.

Moreover, Citizen Groups offer four explanations for how the Rule serves the public interest. *See* Cit.Grps. at 47-49. Two of the four reasons are air-quality justifications. Citizen Groups argue the Rule will "benefit[] the environment and public health by reducing emissions of the potent greenhouse gas methane, VOCs that contribute to smog, and carcinogenic air pollutants such as benzene." *Id.* at 47. Additionally, Citizen Groups claim "the Rule will play an important role in slowing the pace of climate change." *Id.* at 48; *see also* Govt. at 63 (listing the Rule's impact on climate change as a reason that an injunction does not serve the public interest). Notwithstanding the fact this Rule has virtually zero impact on climate change, Pets. at 41-43,

these justifications are yet more evidence the Rule is aimed at air quality control, not waste prevention, and that BLM cannot rationalize the Rule without citing to its alleged impacts on global climate change.

V. CONCLUSION

Respondents' briefs focus on the intricacies and nuanced history of BLM's waste prevention authority in an attempt to obfuscate Petitioners' assertion that BLM acted without authority in promulgating a comprehensive air quality regulatory scheme. Petitioners do not dispute BLM has statutory authority to manage waste and do not ask the Court to define the precise limits of such authority. Petitioners ask this Court to recognize that Congress has not authorized BLM to promulgate this sweeping Rule, and also ask the Court to require BLM to meet the burdens administrative law imposes on the agency. Petitioners demonstrate they are likely to succeed on the merits here. Petitioners also demonstrate the Rule will cause Petitioners and their members irreparable harm, and the equities and public interest favor a preliminary injunction. Thus, the Court should grant Petitioners' motion and enjoin BLM from implementing its final Rule until resolution of this litigation.

WHEREFORE, Petitioners Western Energy Alliance and the Independent Petroleum Association of America respectfully request that this Court grant its motion for preliminary injunction.

Dated this 23rd day of December, 2016.

Respectfully submitted,

DAVIS GRAHAM & STUBBS LLP

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A ROADMAP TO REPEAL: REMOVING REGULATORY BARRIERS TO OPPORTUNITY

FREEDOM PARTNERS

President Obama has imposed an unprecedented onslaught of regulatory costs on the U.S. economy. Since 2009, federal agencies have issued more than 600 major regulations with a total cost exceeding $700 billion. These regulations have erected barriers to opportunity for millions of American families, resulting in the weakest workforce in nearly 40 years.

Freedom Partners strongly supports efforts by President-elect Trump and the new Congress to repeal as many of President Obama's executive actions and regulations as possible. Removing these barriers to opportunity is among the surest ways to jumpstart the U.S. economy and create more opportunity for all.

Unfortunately, repealing federal regulations is not as simple as it sounds. A successful strategy must be considered in three steps and will require action from the administration, Congress, and the courts. Additionally, Freedom Partners urges Congress to put lawmakers on record on as many of these regulations as possible so that voters can see where they stand and hold them accountable in 2018.

STEP 1. WHAT CAN BE REPEALED IN THE FIRST 100 DAYS

Executive actions, proposed regulations, and recently finalized regulations.

- **Executive Actions and Proposed Regulations:** President-elect Trump can unilaterally rescind any executive action signed by President Obama or proposed regulations that have yet to be finalized, including, but not limited to:
    - Executive order establishing a task force on commercial advocacy
    - Executive order putting a moratorium on new federal coal leases
    - Presidential memorandum requiring new federal overtime rule promulgation
    - Paris Climate Agreement requiring greenhouse gas emissions reductions
    - Proposed Environmental Protection Agency (EPA) programs incidental to the Clean Power Plan
    - Proposed Consumer Financial Protection Bureau (CFPB) payday and vehicle title loan rules
    - Proposed CFPB arbitration rules
- **Regulations Finalized On or After June 13, 2016:** Under the Congressional Review Act (CRA), Congress can avoid a Senate filibuster to repeal all regulations finalized during the last 60 legislative days, with June 13, 2016, being the cutoff date. Congress should prioritize the following:
    - Final Stream Protection Rule regarding coal mine permitting
    - Bureau of Land Management (BLM) federal lands Methane Rule
    - Environmental Protection Agency (EPA) Renewable Fuel Standard (RFS): 2017 and 2018 obligations
    - EPA Greenhouse Gas Emissions Standards: Medium- and Heavy-Duty Engines and Vehicles

STEP 2. LONGER-TERM OPPORTUNITIES

All other regulations passed before June 13, 2016 can be repealed in at least one of three ways.

- **Executive Rulemaking, Legislation to Rescind or Defund, and Judicial Challenges.** These are time-consuming processes that should begin immediately. President-elect Trump and Congress should prioritize the following:

  - EPA Rule defining The Waters of the United States
  - EPA Clean Power Plan
  - HHS Electronic Health Record Incentive Program
  - HHS Establishment of Exchanges and Qualified Health
  - DOL Overtime Rule
  - DOL Fiduciary Rule
  - FCC "Net Neutrality" Rule
  - USDA Calorie Labeling for Vending Machines

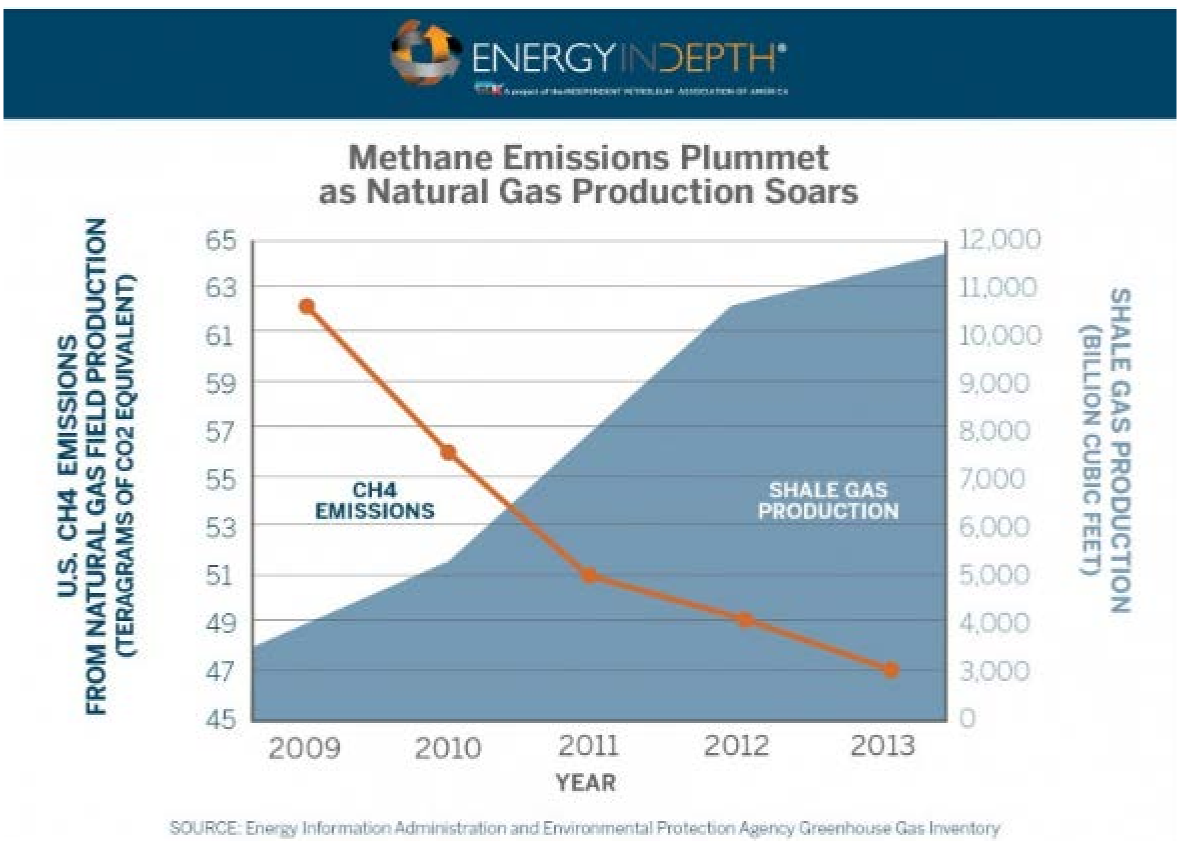
STEP 3. POLITICAL ACCOUNTABILITY

Freedom Partners will hold lawmakers who oppose regulatory relief accountable for their positions.

- **Floor Time:** Congressional leaders should devote sufficient floor time to voting on finalized regulations and putting lawmakers on record on President Obama's most harmful regulations.

- **Voter Education:** Network organizations will educate voters about their elected representatives' positions on regulations that impose barriers to opportunity for hardworking families.

Midnight Methane Madness: Post-election Regulation Threatens to Undermine Energy Revolution



By Dan Byers

We recently wrote about the push by the 115th Congress to use the Congressional Review Act (CRA) to stop several 11th-hour rules issued in the waning days of the Obama Administration. **According to one estimate, a record 38 "major rules" (that is, costing $100 million or more) were promulgated by federal agencies after President Trump's election victory on November 8th.**

While Congress is expected to vote on several rules early in 2017, energy-related measures will dominate the first tranche of resolutions, including **the Bureau of Land Management's so-called "Methane and Waste Reduction Rule" covering methane leaking, venting, and flaring**. Finalized on November 18th, 2016—ten days *after* the election—this rule effectively handcuffs the energy revolution by imposing unnecessary new controls and restrictions on oil and natural gas production.

While energy companies have every incentive to minimize venting and flaring of natural gas from oil and gas wells, they sometimes must do so either for safety purposes or due to a lack of sufficient infrastructure to transport the natural gas to market. Nonetheless, through technological innovation, industry has successfully and voluntarily reduced methane emissions, cleaning the air even as natural gas production has grown significantly. Information from the Western Energy Alliance and Energy-in-Depth illustrates the extent of this success story:

- **Methane emissions from natural gas production have declined by 38% since 2005 without federal regulation** while gas production has increased by 33% across the nation during that time. **Methane emissions from oil production have also fallen by 21% since 1990.**

- The simultaneous increase in natural gas production and decrease in methane emissions is thanks to a plummeting leak rate. The Environmental Protection Agency estimates system-wide natural gas leakage rates at 1.1%. Two recent studies by the Environmental Defense Fund and the University of Texas find that methane emissions from natural gas production sites are even lower, 0.38% of production.

Though ostensibly intended to reduce methane emissions and increase government royalties, **BLM's 11th hour rule is so onerous and costly that it will make energy development uneconomical in many areas.** Rather than strengthen environmental practices, this command-and-control regulatory approach from Washington bureaucrats will simply chase energy developers away, ironically reducing royalty revenues in the process. Adding to this irony is the fact that BLM's inaction on pipeline permits means companies, with no transport options, have no other option but to...vent and flare.

Ultimately, this regulation handcuffs the energy revolution, makes us more dependent on foreign sources of energy, and translates to higher costs for families and businesses. **A vote to eliminate this costly rule will help further President Trump's and the Congressional majorities' desire for greater domestic**

energy production, infrastructure development, and jobs.

the latest

Letters

Feb 1 2017

Key Vote Alert! H.J. Res. 38, to disapprove BLM Stream Rule

The U.S. Chamber of Commerce will consider including votes in our 2017 How They Voted scorecard related to H.J. Res. 38 and H.J. Res. 41, which would undo two onerous and unnecessary Obama-era rules on streams and resource extraction.

Letters

Feb 1 2017

Chamber Coalition Letter to Congress Supporting Nullification of BLM Stream Rule

As business leaders representing diverse geographic regions and economic interests, we write to encourage your support for expedited passage of a joint Congressional Review Act (CRA) resolution vetoing the Obama Administration's so-called "Stream Protection Rule" (SPR).

A last minute Obama regulation could crush jobs and American energy development. But YOU can take action to stop it! http://bit.ly/2jRupPD

STATEMENT BY SENATOR JOHN McCAIN ON BLM METHANE RECAPTURE RULE

May 10 2017

Washington, D.C. – U.S. Senator John McCain (R-AZ) released the following statement on his vote today against a motion to proceed to a resolution to overturn the Bureau of Land Management's (BLM) methane recapture rule:

"Today I voted against a procedural motion that would have brought a resolution to the Senate floor to overturn the BLM methane recapture rule.

"Improving the control of methane emissions is an important public health and air quality issue, which is why some states are moving forward with their own regulations requiring greater investment in recapture technology. I join the call for strong action to reduce pollution from venting, flaring and leaks associated with oil and gas production operations on public and Indian land. While I am concerned that the BLM rule may be onerous, passage of the resolution would have prevented the federal government, under any administration, from issuing a rule that is 'similar,' according to the plain reading of the Congressional Review Act.

"I believe that the public interest is best served if the Interior Department issues a new rule to revise and improve the BLM methane rule. I look forward to working with my colleagues who voted to proceed to the resolution today."

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Permalink: https://www.mccain.senate.gov/public/index.cfm/2017/5/statement-by-senator-john-mccain-on-blm-methane-recapture-rule

4310-84

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Part 3170

[17X.LLWO310000.L13100000.PP0000]

RIN 1004-AE14

Waste Prevention, Production Subject to Royalties, and Resource Conservation; Postponement of Certain Compliance Dates

AGENCY: Bureau of Land Management, Interior.

ACTION: Notification; postponement of compliance dates.

SUMMARY: On November 18, 2016, the Bureau of Land Management (BLM) issued a final rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" (the "Waste Prevention Rule" or "Rule"). Immediately after the Waste Prevention Rule was issued, petitions for judicial review of the Rule were filed by industry groups and States with significant BLM-managed Federal and Indian minerals. This litigation has been consolidated and is now pending in the U.S. District Court for the District of Wyoming. In light of the existence and potential consequences of the pending litigation, the BLM has concluded that justice requires it to postpone the compliance dates for certain sections of the Rule pursuant to the Administrative Procedure Act, pending judicial review.

DATES: [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]

FOR FURTHER INFORMATION CONTACT: Timothy Spisak at the BLM Washington Office, 20 M Street SE, Room 2134 LM, Washington, D.C. 20003, or by

telephone at 202-912-7311. For questions relating to regulatory process issues, contact Faith Bremner at 202-912-7441.

Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service (FRS) at 1-800-877-8339 to contact these individuals during normal business hours. FRS is available 24 hours a day, 7 days a week to leave a message or question with these individuals. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

I. Background

On November 18, 2016, the BLM published the Waste Prevention Rule. (81 FR 83008) The Rule addresses, among other things, the loss of natural gas through venting, flaring, and leaks during the production of Federal and Indian oil and gas. The Rule replaced Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (1980) ("NTL-4A"), which governed the venting and flaring of Federal and Indian gas for more than three decades. In addition to updating and revising the requirements of NTL-4A, the Rule contained new requirements that operators capture a certain percentage of the gas they produce (43 CFR 3179.7), measure flared volumes (43 CFR 3179.9), upgrade or replace pneumatic equipment (43 CFR 3179.201 – 3179.202), capture or combust storage tank vapors (43 CFR 3179.203), and implement leak detection and repair (LDAR) programs (43 CFR 3179.301 – .305). The Rule did not obligate operators to comply with these new requirements until January 17, 2018. Compliance with certain other provisions of the Rule is already mandatory, including the requirement that operators submit a "waste

minimization plan" with applications for permits to drill (43 CFR 3162.3-1), new regulations for the royalty-free use of production (43 CFR subpart 3178), new regulatory definitions of "unavoidably lost" and "avoidably lost" oil and gas (43 CFR 3179.4), limits on venting and flaring during drilling and production operations (43 CFR 3179.101 – 3179.105), and requirements for downhole well maintenance and liquids unloading (43 CFR 3179.204).

Immediately after the Rule was issued, petitions for judicial review of the Rule were filed by industry groups and States with significant BLM-managed Federal and Indian minerals. The petitioners in this litigation are the Western Energy Alliance (WEA), the Independent Petroleum Association of America, the State of Wyoming, the State of Montana, the State of North Dakota, and the State of Texas. This litigation has been consolidated and is now pending in the U.S. District Court for the District of Wyoming. *Wyoming v. U.S. Dep't of the Interior*, Case No. 2:16-cv-00285-SWS (D. Wyo.). Petitioners assert that the BLM was arbitrary and capricious in promulgating the Rule and that the Rule exceeds the BLM's statutory authority.

On March 28, 2017, the President issued Executive Order No. 13783 (EO 13783) entitled, "Promoting Energy Independence and Economic Growth." EO 13783 directed the Secretary of the Interior (Secretary) to review the Rule for consistency with the policies set forth in Section 1 of EO 13783 and, if appropriate, publish for notice and comment a proposed rule suspending, revising, or rescinding the Rule. EO 13783 Sec. 7(b). On March 29, 2017, the Secretary issued Secretarial Order 3349 implementing EO 13783. The Department's review of the Rule is ongoing.

The Secretary has received written requests from WEA and the American Petroleum Institute (API) that the BLM suspend the Rule or postpone its compliance dates in light of the regulatory uncertainty created by the pending litigation and the ongoing administrative review of the Rule. Letter from Kathleen M. Sgamma to Secretary Zinke (April 4, 2017); letter from Jack N. Gerard to Secretary Zinke (May 16, 2017). Both API and WEA stated that operators face the prospect of significant expenditures to comply with provisions of the Rule that will become operative in January 2018. WEA specifically noted that the LDAR, storage tank, and pneumatic device provisions will require operators to begin purchasing and installing tens of thousands of replacement parts in the near future.

Section 705 of the Administrative Procedure Act (APA), 5 U.S.C. 705, provides that, "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review." The Rule obligates operators to comply with its "capture percentage," flaring measurement, pneumatic equipment, storage tank, and LDAR provisions beginning on January 17, 2018. This compliance date has not yet passed and is within the meaning of the term "effective date" as that term is used in Section 705 of the APA. Considering the substantial cost that complying with these requirements poses to operators (see U.S. Bureau of Land Management, Regulatory Impact Analysis for: Revisions to 43 CFR subpart 3100 (Onshore Oil and Gas Leasing) and 43 CFR subpart 3600 (sic) (Onshore Oil and Gas Operations), Additions of 43 CFR subpart 3178 (Royalty-Free Use of Lease Production) and 43 CFR subpart 3179 (Waste Prevention and Resource Conservation) (November 10, 2016)), and the uncertain future these requirements face in light of the pending litigation and administrative review of the

Rule, the BLM finds that justice requires it to postpone the future compliance dates for the following sections of the Rule: 43 CFR 3179.7, 3179.9, 3179.201, 3179.202, 3179.203, and 3179.301–3179.305.

While the BLM believes the Waste Prevention Rule was properly promulgated, the petitioners have raised serious questions concerning the validity of certain provisions of the Rule. Given this legal uncertainty, operators should not be required to expend substantial time and resources to comply with regulatory requirements that may prove short-lived as a result of pending litigation or the administrative review that is already under way. Postponing these compliance dates will help preserve the regulatory status quo while the litigation is pending and the Department reviews and reconsiders the Rule.

The provisions with compliance dates that have passed and are therefore unaffected by this document include: the requirement that operators submit a "waste minimization plan" with applications for permits to drill (43 CFR 3162.3-1), new regulations for the royalty-free use of production (43 CFR subpart 3178), new regulatory definitions of "unavoidably lost" and "avoidably lost" oil and gas (43 CFR 3179.4), limits on venting and flaring during drilling and production operations (43 CFR 3179.101 – 3179.105), and requirements for downhole well maintenance and liquids unloading (43 CFR 3179.204).

Separately, the BLM intends to conduct notice-and-comment rulemaking to suspend or extend the compliance dates of those sections affected by the Rule.

II. Postponement of Compliance Dates

Pursuant to Section 705 of the APA, the BLM hereby postpones the future compliance dates for the following sections affected by the final rule entitled, "Waste

Prevention, Production Subject to Royalties, and Resource Conservation", pending judicial review: 43 CFR 3179.7, 3179.9, 3179.201, 3179.202, 3179.203, and 3179.301–3179.305. BLM will publish a document announcing the outcome of that review.

____June 9, 2017________

Date

Katharine S. MacGregor
Delegated the Authority of the
Assistant Secretary for Land and Minerals
Management

[FR Doc. 2017-12325 Filed: 6/14/2017 8:45 am; Publication Date: 6/15/2017]

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

STATE OF CALIFORNIA, et al., Plaintiffs, v. UNITED STATES BUREAU OF LAND MANAGEMENT, et al., Defendants.	Related Case Nos. 17-cv-03804-EDL, 17-cv-3885-EDL **ORDER GRANTING PLAINTIFFS' MOTIONS FOR SUMMARY JUDGMENT** Re: Dkt. Nos. 11, 37
SIERRA CLUB, et al., Plaintiffs, v. RYAN ZINKE, et al., Defendants.	

The State of California, together with the State of New Mexico, and a coalition of seventeen conservation and tribal citizens groups, brought suit against the Bureau of Land Management (the "Bureau"), Secretary of the Department of the Interior Ryan Zinke, and Acting Assistant Secretary for Land and Minerals Management, Department of the Interior Katharine S. MacGregor (collectively, "Defendants"), alleging that Defendants violated the Administrative Procedures Act ("APA") when the Bureau published a notice in the Federal Register postponing the compliance dates for certain sections of the Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule after the rule's effective date had already passed. Before the Court are Plaintiffs' motions for summary judgment. For the following reasons, the Court GRANTS both motions.

United States District Court
Northern District of California

I. BACKGROUND

On November 18, 2016, the Bureau, an agency within the U.S. Department of the Interior, issued the Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule (the "Rule"). See 81 Fed. Reg. 83,008. The Rule's purpose was to "reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian (other than Osage Tribe) leases . . . [and] also clarify when produced gas lost through venting, flaring, or leaks is subject to royalties, and when oil and gas production may be used royalty-free on-site." Id. The Rule was promulgated to replace the then-existing regulations related to venting, flaring, and royalty-free use of gas contained in the 1979 Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A). Id. The Rule's effective date was January 17, 2017. Id.

The Bureau began developing the Rule in 2014 in response to reviews from the Government Accountability Office and the Department of the Interior's Office of the Inspector General which concluded that the Bureau's then-existing regulations regarding waste and royalties were "insufficient and outdated." Id. at 83,009-10. The regulations in place in 2014 had not been revisited in at least three decades. Id. at 83,008. After receiving input from various stakeholders and the public, the Bureau released its proposed rule in February 2016. See 81 Fed. Reg. 6,616 (Feb. 8, 2016) (the "Proposed Rule"). To assist in gathering stakeholder comment before publishing the Proposed Rule, the Bureau conducted a series of forums in Colorado, New Mexico, North Dakota, and Washington, D.C., and held numerous meetings and calls with state representatives, individual companies, trade associations, and non-governmental organizations. Id. at 6,617. The Bureau received approximately 330,000 public comments on the Proposed Rule. See 81 Fed. Reg. 83,021.

At the time the Bureau finalized the Rule in November 2016, two industry groups and the States of Wyoming and Montana (later joined by North Dakota and Texas as intervenors) filed legal challenges to the validity of the Rule in federal court in Wyoming. See Western Energy Alliance et al. v. Secretary of the U.S. Dep't of the Interior et al., Case No. 16-cv-00280-SWS (D. Wyo. filed Nov. 15, 2016); State of Wyoming et al. v. United States Dep't of the Interior et al.,

Case No. 16-cv-00285-SWS (D. Wyo. filed Nov. 18, 2016). They alleged that the Bureau did not have statutory authority to regulate air pollution and that the Rule was arbitrary and capricious.[1] The plaintiffs moved for entry of a preliminary injunction to prevent the Rule from going into effect, which the court denied on January 16, 2017. See State of Wyoming et al. v. United States Dep't of the Interior et al., 2017 WL 161428 (D. Wyo. Jan. 16, 2017).

On January 17, 2017, the Rule went into effect. Approximately two months later, on March 28, 2017, the President issued Executive Order No. 13783, which instructed each executive agency to review all agency actions to identify those that:

> potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.

82 Fed. Reg. 16,093. On March 29, 2017, Secretary Zinke issued Secretarial Order No. 3349 to implement the executive order as it pertains to the regulatory actions of the Department of the Interior. See Secretarial Order No. 3349, available at https://www.doi.gov/sites/doi.gov/files/uploads/so_3349_-american_energy_independence.pdf.

On June 15, 2017, the Bureau issued a notice in the Federal Register that it was postponing the compliance dates for certain sections of the Rule. See Waste Prevention, Production Subject to Royalties, and Resource Conservation; Postponement of Certain Compliance Dates, 82 Fed. Reg. 27,430 (the "Postponement Notice"). The postponed sections of the Rule were subject to a compliance date of January 17, 2018. Id. The Postponement Notice invoked Section 705 of the APA and concluded that "justice requires [the Bureau] to postpone the future compliance dates for [certain] sections of the Rule" in light of "the substantial cost that complying with these requirements poses to operators . . . and the uncertain future these requirements face in light of the pending litigation and administrative review of the Rule." Id. at 27,431. The "pending litigation" referred to the legal challenges in the District of Wyoming. Id. The Postponement Notice stated that the Bureau interpreted the January 17, 2018 compliance date for these sections of the Rule to

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[1] All Plaintiffs to this case, with the exception of Fort Berthold Protectors of Water and Earth Rights, intervened in the two cases in the District of Wyoming.

be "within the meaning of the term 'effective date' as that term is used in Section 705 of the APA." Id. It further explained that the Bureau "believes the [Rule] was properly promulgated," but determined that "[p]ostponing these compliance dates will help preserve the regulatory status quo while the litigation is pending and the Department reviews and reconsiders the Rule." Id. The Postponement Notice did not apply to provisions of the Rule with compliance dates that had already passed. Id. It concluded by noting that the Bureau "intend[ed] to conduct notice-and-comment rulemaking to suspend or extend the compliance dates of those sections affected by the Rule." Id.

In a status report filed in the District of Wyoming litigation on September 1, 2017, the Bureau stated that it has drafted a proposed rule to suspend certain provisions of the Rule that were affected by the Postponement Notice and that proposed notice is currently under review by the Office of Information and Regulatory Affairs in the Office of Management and Budget before it is published for comment. See Western Energy Alliance et al. v. Secretary of the U.S. Dep't of the Interior et al., Case No. 16-cv-00280-SWS, Dk. No. 131; State of Wyoming et al. v. United States Dep't of the Interior et al., Case No. 16-cv-00285-SWS, Dkt. No. 136. According to the same status report, the Bureau is also developing a proposed rule to revise the Rule pursuant to Executive Order No. 13783. Id.

II. PROCEDURAL HISTORY

Plaintiffs the State of California and the State of New Mexico filed suit on July 5, 2017, alleging that the decision by Defendants to postpone certain compliance dates of the Rule violated the APA. On July 12, 2017, the Court granted Plaintiffs' unopposed motion to relate this case to another case pending before this Court, Sierra Club et al. v. Zinke et al., Case No. 17-cv-03885-EDL, which was filed by seventeen conservation and tribal organizations (the "Conservation and Tribal Citizen Groups" or the "Groups") [2] on July 10, 2017.

[2] The organizations that comprise the Conservation and Citizen Tribal Groups are: Sierra Club, Center for Biological Diversity, Environmental Defense Fund, National Wildlife Federation, Natural Resources Defense Council, The Wilderness Society, Citizens for a Healthy Community, Dine Citizens Against Ruining Our Environment, Earthworks, Environmental Law and Policy Center, Fort Berthold Protectors of Water and Earth Rights, Montana Environmental Information Center, San Juan Citizens Alliance, Western Organization of Resource Councils, Wilderness

Since the filing of these lawsuits, the Court has granted motions to intervene by the State of North Dakota, the Independent Petroleum Association of America, and the Western Energy Alliance (together, the "Intervenors"). Plaintiffs and Defendants did not oppose the Intervenors' motions, so long as their intervention was subject to certain conditions. Those conditions were that Intervenors: (1) file joint briefs and abide by all existing schedules in the litigation, including the stipulated briefing schedule on the motions for summary judgment; (2) not raise new claims or otherwise expand the litigation; and (3) abide by the same constraints applicable to parties in any APA case, in which judicial review of the challenged agency decision is generally limited to the agency's administrative record. Intervenors either expressly agreed to these conditions (State of North Dakota) or expressly agreed to some conditions and did not object to others (Independent Petroleum Association of America and the Western Energy Alliance). The Court concluded that the proposed conditions were reasonable and necessary in the interests of judicial economy, sound case management, and avoiding undue delay, and granted the motions to intervene subject to those conditions.

On July 26, 2017, the State of California and the State of New Mexico filed a motion for summary judgment in <u>State of California et al. v. U.S. Bureau of Land Management et al.</u>, Case No. 17-cv-03804-EDL. The next day, on July 27, 2017, the Conservation and Tribal Citizen Groups filed a motion for summary judgment in <u>Sierra Club et al. v. Zinke et al.</u>, Case No. 17-cv-03885-EDL. Defendants opposed the motions, and Intervenors joined in Defendants' opposition briefs. Intervenors have not filed separate motions for summary judgment or oppositions to Plaintiffs' motions.

On July 26, 2017, Defendants filed a motion to transfer these cases to the United States District Court for the District of Wyoming. As noted above, Defendants are currently defending a challenge to the validity of the Rule before that court. The States of California and New Mexico and, separately, the Conservation and Trial Citizens Groups filed opposition briefs to the motion to transfer on August 9, 2017. The parties agreed that the motion to transfer was suitable for

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Workshop, WildEarth Guardians, and Wyoming Outdoor Council.

decision without a hearing. On August 10, 2017, Defendants moved to stay briefing and the hearing on Plaintiffs' motions for summary judgment in both cases on the grounds that the Court should first resolve Defendants' motion to transfer the cases to the District of Wyoming. Plaintiffs opposed the motion. The Court denied Defendants' motion to stay on August 23, 2017, concluding that a stay would not meaningfully conserve judicial resources and that Plaintiffs had shown more than a fair possibility of harm due to the proposed stay, while Defendants had not established "a clear case of hardship or inequity" required for a stay. On September 7, 2017, the Court denied the motion to transfer, concluding that, among other reasons, there were no overlapping factual or legal issues that warranted overriding Plaintiffs' choice of forum. Case No. 17-cv-3804, Dkt. No. 73; Case No. 17-cv-3885, Dkt. No. 62.

Upon reviewing inquiries from numerous groups seeking to file amicus briefs regarding Plaintiffs' motions for summary judgment, the Court issued an order permitting interested parties to file administrative motions for leave to file an amicus brief by September 6, 2017. Subsequently, the Court granted three motions for leave to file amicus briefs by the States of Washington, Oregon, Maryland, and New York; a coalition of the National Association of Home Builders, American Fuel & Petrochemical Manufacturers, American Petroleum Institute, and National Mining Association; and the Institute for Policy Integrity at New York University.

III. LEGAL STANDARD

Summary judgment shall be granted if "the pleadings, discovery and disclosure materials on file, and any affidavits show that there is no genuine issue as to any material fact and that the movant is entitled to judgment as a matter of law." Fed. R. Civ. Pro. 56(c). Material facts are those which may affect the outcome of the case. See Anderson v. Liberty Lobby, Inc., 477 U.S. 242, 248 (1986). A dispute as to a material fact is genuine if there is sufficient evidence for a reasonable jury to return a verdict for the nonmoving party. Id. The court must view the facts in the light most favorable to the non-moving party and give it the benefit of all reasonable inferences to be drawn from those facts. Matsushita Elec. Indus. Co. v. Zenith Radio Corp., 475 U.S. 574, 587 (1986). The court must not weigh the evidence or determine the truth of the matter, but only determine whether there is a genuine issue for trial. Balint v. Carson City, 180 F.3d

1047, 1054 (9th Cir. 1999).

A party seeking summary judgment bears the initial burden of informing the court of the basis for its motion, and of identifying those portions of the pleadings and discovery responses that demonstrate the absence of a genuine issue of material fact. Celotex Corp. v. Catrett, 477 U.S. 317, 323 (1986). Where the moving party will have the burden of proof at trial, it must affirmatively demonstrate that no reasonable trier of fact could find other than for the moving party. On an issue where the nonmoving party will bear the burden of proof at trial, the moving party can prevail merely by pointing out to the district court that there is an absence of evidence to support the nonmoving party's case. Id. If the moving party meets its initial burden, the opposing party "may not rely merely on allegations or denials in its own pleading;" rather, it must set forth "specific facts showing a genuine issue for trial." See Fed. R. Civ. P. 56(e)(2); Anderson, 477 U.S. at 250. If the nonmoving party fails to show that there is a genuine issue for trial, "the moving party is entitled to judgment as a matter of law." Celotex, 477 U.S. at 323.

IV. DISCUSSION

A. Conservation and Tribal Citizen Groups' Standing

The Conservation and Tribal Citizen Groups briefed their standing to bring their lawsuit under the doctrine of associational standing. Defendants have not opposed the Conservation and Trial Citizens Groups' motion for summary judgment for lack of standing.

Under the doctrine of associational standing, "an association has standing to bring suit on behalf of its members when: (a) its members would otherwise have standing to sue in their own right; (b) the interests it seeks to protect are germane to the organization's purpose; and (c) neither the claim asserted nor the relief requested requires the participation of individual members in the lawsuit." Hunt v. Wash. State Apple Advert. Comm'n, 432 U.S. 333, 343 (1977).

The Groups' individual members meet the standing requirements in their own right. To do so, they must show that the individual members have: "(1) suffered an 'injury in fact' that is (a) concrete and particularized and (b) actual or imminent, not conjectural or hypothetical; (2) the injury is fairly traceable to the challenged action of the defendant; and (3) it is likely, as opposed to merely speculative, that the injury will be redressed by a favorable decision." Friends of the

Earth, Inc. v. Laidlaw Envtl. Servs., Inc., 528 U.S. 167, 180-81 (2000) (citation omitted). Many of their members live in states or are members of tribes that receive royal benefits that fund many important public services, such as education and infrastructure, and their governments will receive lower royalty payments due to the Postponement Notice. See Nat'l Wildlife Fed'n v. Burford, 871 F.2d 849, 853-54 (9th Cir. 1989). Other members own tribal mineral rights and will also receive lower royalty payments. Further, many of their members live and work on or near public and tribal lands that are impacted by oil and gas drilling and the production and venting, flaring, and leaking associated with that drilling. As a result of the postponement of the Rule's regulations to reduce waste and curb emissions, the members' use and enjoyment of these lands will be diminished, including because of detrimental health impacts that some members have already experienced and the aesthetic harm that will arise from venting, flaring, and leaking practices. See Hall v. Norton, 266 F.3d 969, 976 (9th Cir. 2001). Finally, their members suffered a procedural injury when the Postponement Notice was issued without the opportunity for public comment. See Wildearth Guardians v. U.S. Dep't of Ag., 795 F.3d 1148, 1154 (9th Cir. 2015); Citizens for Better Forestry v. U.S. Dep't of Ag., 341 F.3d 961, 970 (9th Cir. 2003). At the same time, their members' individual participation is not necessary.

As to the interests being germane, the Groups have submitted declarations affirming that "reducing waste and air and climate pollution from oil and gas development on public lands is central to the Conservation and Tribal Citizen Groups' institutional missions." Groups' Mot. at 20; Ex. 1, Standing Decls. at 1, 75, 90-91, 102, 106, 119, 128, 136. The Groups were also actively involved in the development of the Rule and defending the Rule's validity in the District of Wyoming litigation. See Groups' Mot., Ex. 1. As to the third element, as the issues raised here are purely legal and do not require any involvement of the individual members or their "unique facts" to resolve the issues raised or grant the relief sought. See Int'l Union, United Auto, Aerospace & Ag. Implement Workers of Am. v. Brock, 477 U.S. 274, 287-88 (1986).

The injuries discussed above are traceable to the postponement of the Rule because the postponed provisions would have reduced waste of royalty-bearing resources and reduce emissions of air pollutants and greenhouse gases. A ruling in the Groups' favor vacating the

Postponement Notice and directing the Bureau to implement the Rule would redress their members' injuries.

Accordingly, the Groups have associational standing to bring this lawsuit.

B. Timing of Motions

Defendants contend that the Court should not reach the merits of Plaintiffs' motions for summary judgment because they are premature, having been filed before Defendants have answered the complaint, before the initial case management conferences, and before Defendants have filed an administrative record. They argue that Plaintiffs are seeking to evade the APA's requirement that the court review an agency action based on the administrative record. See 5 U.S.C. § 706 ("[T]he court shall review the whole record or those parts of it cited by a party[.]").

These motions are timely under Rule 56 and the Court is fully able to resolve the motions at this phase of the litigation because they are limited to legal issues that do not depend on the administrative record, aside from the few key documents the parties cited in their motions, which the Defendants do not dispute are subject to judicial notice.[3] See Wagner v. Spire Vision, 2014 WL 889483, at *4 (N.D. Cal. Mar. 3, 2014) (explaining that motions for summary judgment are appropriate for deciding purely legal issues); Fed. R. Civ. P. 56 ("a party may file a motion for summary judgment at any time until 30 days after the close of all discovery"). The administrative record would not be helpful to decide these issues and is not required. See People for the Ethical Treatment of Animals, Inc. v. U.S. Dep't of Ag., 194 F. Supp. 3d 404, 409 (E.D.N.C. 2016); Animal Legal Def. Fund v. U.S. Dep't of Ag., 789 F.3d 1206, 1224 n.13 (11th Cir. 2015). Defendants have not identified any documents that are not currently before the Court that are required to resolve any purported factual issues. Nor have Defendants asked for relief under Rule 56(d) of the Federal Rules of Civil Procedure allowing nonmoving parties that oppose summary judgment to request a delay in hearing the motion because they need more time to enable them to

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[3] Specifically, Plaintiffs the State of California and the State of New Mexico have requested judicial notice of five documents, including the Proposed Rule, the Rule, and the Postponement Notice.

present facts essential to justify their opposition.[4] In short, there is no reason to wait for the administrative record to resolve the legal issues that are currently before the Court.

C. Standard of Review

As the parties are aware, this Court recently decided a case against the Department of the Interior that raised many of the same issues presented in this case. See Becerra v. U.S. Dep't of Interior, Case No. 17-cv-02376-EDL, 2017 WL 3891678 (N.D. Cal. Aug. 30, 2017). With respect to the standard of review that the Court must apply to Plaintiffs' challenge, Defendants point out, as they did in Becerra, that the APA may set aside an agency action only if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law, . . . in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; [or] without observance of procedure required by law," 5 U.S.C. § 706. Yet Defendants focus only on the standard of review under the first clause regarding arbitrary action and abuse of discretion. Defendants are correct that in general review under that prong of the statute "is narrow, and a court is not to substitute its judgment for that of the agency." Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins., 463 U.S. 29, 43 (1983). In that context, an agency's decision can be set aside "only if the agency relied on factors Congress did not intend it to consider, entirely failed to consider an important aspect of the problem, or offered an explanation that runs counter to the evidence before the agency or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." Earth Island Inst. v. U.S. Forest Serv., 697 F.3d 1010, 1013 (9th Cir. 2012) (quoting Winter v. Nat. Res. Def. Council, Inc., 555 U.S. 7 (2008)).

As this Court recognized in Becerra, however, that standard is not applicable to actions short of statutory right or taken in violation of legally required procedures, which is the threshold issue that Plaintiffs raise here. To the contrary, section 706 provides that, "[t]he reviewing court shall . . . hold unlawful and set aside agency action, findings, and conclusions found to be . . . in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." 5 U.S.C. § 706(2)(C). The "arbitrary and capricious" standard forms a separate basis to set aside agency

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[4] Indeed, Defendants stipulated to a briefing schedule for the summary judgment motions that did not provide for the filing of an administrative record.

action, 5 U.S.C. § 706(2)(A), and it is that standard which Motor Vehicles Mfs. characterized as narrow. 463 U.S. at 42-43. Similarly, Defendants rely on a portion of Earth Island Institute in which the court cites Lands Council v. McNair, 537 F.3d 981, 987 (9th Cir. 2008) for exposition of the arbitrary and capricious standard. See Earth Island Institute, 697 F.3d at 1013; see also Price v. Stevedoring Servs. of Am., Inc., 697 F.3d at 825-26 (holding that litigating position of Director of Office of Workers' Compensation Programs in interpreting Longshore Act was not entitled to Chevron deference where Director did not adopt his litigating positions through any relatively formal administrative procedure, but through internal decision-making not open to public comment or determination, and there was no other indication that Congress intended Director's litigating positions to carry force of law).

As Plaintiffs persuasively argue, the Bureau's decision to postpone the Rule is not entitled to deference. Chevron U.S.A., Inc. v. Natural Res. Def. Council, 467 U.S. 837, 842 (1984) held that "the court must first give effect to the unambiguously expressed intent of Congress" when reviewing an agency's interpretation of a statute. Under United States v. Mead Corp., 533 U.S. 218, 226-27 (2001) and Price v. Stevedoring Servs. of Am., Inc., 697 F.3d 820, 826 (9th Cir. 2012), Chevron deference is warranted only when an agency is exercising authority delegated to it by Congress to administer a particular statute, and that Congress has not delegated the Bureau authority to administer the APA. By contrast, Motor Vehicles Mfs. addressed agency action delegated to that agency by the Motor Vehicle Safety Act. 463 U.S. 29. Similarly, in Earth Island Institute, the Ninth Circuit held that the Forest Service is entitled to deference as to its interpretation of its own forest plans unless that interpretation is plainly inconsistent with the plan. 697 F.3d at 1013.

The underlying dispute here, however, centers upon the Bureau's application of section 705 of the APA. Under Mead Corp., "administrative implementation of a particular statutory provision qualifies for Chevron deference when it appears that Congress delegated authority to the agency generally to make rules carrying the force of law, and that the agency interpretation claiming deference was promulgated in the exercise of that authority." Mead, 533 U.S. at 226-27.

Defendants have not pointed to any authority delegating the Bureau authority to interpret

section 705 of the APA. As in Becerra, Defendants have failed to show that the Bureau's interpretation of section 705 of the APA is entitled to deference.

D. The Bureau's Invocation of Section 705 of the APA

On June 15, 2017, the Bureau relied on Section 705 of the APA to postpone the compliance date for certain sections of the Rule. Section 705 provides:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court, including the court to which a case may be taken on appeal from or on application for certiorari or other writ to a reviewing court, may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.

Plaintiffs argue that postponing implementation of the Rule after it has already gone into effect runs afoul of the plain language of Section 705. Plaintiffs point to the only decision on this issue, Safety-Kleen Corp. v. Envtl. Prot. Agency, 1996 U.S. App. LEXIS, at *2 (D.C. Cir. Jan. 19, 1996), which held that Section 705 does not permit an agency to suspend a promulgated rule without notice and comment.

In Becerra, as in this case, Defendants contended that the term "effective date" in Section 705 encompasses effective dates *and* compliance dates. This is also the reasoning set forth in the Postponement Notice itself. See 82 Fed. Reg. 27,430. To support their position, Defendants raise several arguments. Defendants argue that in many instances, an agency will not have time to exercise its Section 705 authority after a lawsuit is filed and before the challenged rule's stated effective date, thus rendering the authority provided by the statute of little use. Defendants also argue that "compliance dates" are the "dates with teeth," and Section 705 is meant to allow an agency to maintain the status quo pending judicial review.

In Becerra, the Court rejected all of Defendants' arguments. See Becerra, 2017 WL 3891678, at *8-11. The plain language of the statute authorizes postponement of the "effective date," not "compliance dates." 5 U.S.C. § 705. As the Court of Appeals for the District of Columbia explained when confronting a similar argument about Section 705:

> Upon consideration of the motion of intervenors to vacate administrative stay, the responses thereto and the reply, it is

> ORDERED that the motion be granted. Respondent improperly justified the stay based on 5 U.S.C. § 705 (1994). That statute permits an agency to postpone the effective date of a not yet effective rule, pending judicial review. It does not permit the agency to suspend without notice and comment a promulgated rule, as respondent has attempted to do here. If the agency determines the rule is invalid, it may be able to take advantage of the good cause exception, 5 U.S.C. § 553(b).

Safety-Kleen Corp., 1996 U.S. App. LEXIS, at *2-3.

This reasoning is equally applicable here. Effective and compliance dates have distinct meanings. See Silverman v. Eastrich Multiple Inv'r Fund, L.P., 51 F.3d 28, 31 (3d Cir. 1995) ("The mandatory compliance date should not be misconstrued as the effective date of the revisions."); Nat. Res. Def. Council, Inc. v. U.S. Envtl. Prot. Agency, 683 F.2d 752, 762 (3d Cir. 1982) (stating that an effective date is "an essential part of any rule: without an effective date, the agency statement could have no future effect, and could not serve to implement, interpret, or prescribe law or policy") (internal quotation marks omitted).

Defendants argue that this case is distinguishable from Becerra for two main reasons. First, they contend that the Bureau did not postpone the entire Rule at issue here, whereas the Department of the Interior had postponed the entire rule that was the subject of the litigation in Becerra. Defendant argue that this distinction is important because the Postponement Notice preserved the status quo by leaving in place the parts of the Rule that were effective as of January 17, 2017, while postponing other parts of the Rule that did not require compliance until one year later on January 17, 2018. Under Defendants' interpretation, the parts of the Rule with compliance dates of January 17, 2018 were not yet "effective" at the time that the Bureau issued the Postponement Notice. Thus, because operators in the oil and gas industry were no longer required to prepare for and then achieve compliance at a later date with those parts of the Rule, Defendants contend that the Postponement Notice maintained the status quo because compliance was not mandatory until January 17, 2018.

This reasoning is circular at best. It tacitly acknowledges that the Postponement Notice did not maintain the status quo for those parts of the Rule with a compliance date of January 17, 2018 because the year leading up to that date was intended to give operators in the oil and gas industry the time they needed to adjust their operations to come into compliance. At the time that the

Bureau issued the Postponement Notice on June 15, 2017, the regulated parties either had to start preparing or continue preparing to make the necessary changes in light of the Rule's impending compliance date. Similar to the regulation at issue in Becerra, the Rule imposed compliance obligations starting on its effective date of January 17, 2017 "that increased over time but did not abruptly commence" on January 17, 2018. Becerra, 2017 WL 3891678, at *8. Indeed, as Intervenor Western Energy Alliance stated at oral argument, preparing to meet the January 17, 2018 compliance date could take operators up to six months, depending on the size of the operation. For example, Intervenor Western Energy Alliance stated that large operators needed to begin inspections during the summer of 2017 to complete the new leak prevention and repair obligations by the January 17, 2018 compliance date. While smaller operators would need less time to complete those tasks, Intervenor Western Energy Alliance stated that all operators would need some lead-up time to achieve compliance by January 17, 2018.

Second, Defendants argue that the Rule at issue here, unlike the one in Becerra, specifically referenced compliance dates in the regulation that were meant to phase in over time, which thereby established at least two different "effective dates" under the Rule. Defendants analogize the one-year period between the January 17, 2017 effective date and the January 17, 2018 compliance date with the period between publication of a final rule and its effective date. During the time between publication and its effective date, Section 705 expressly permits the agency to invoke its Section 705 authority pending judicial review. According to Defendants, by analogy, the agency should also be able to use Section 705 after the official effective date but before the January 17, 2018 compliance date comes due because the compliance date is functionally equivalent to a second effective date. Not only is this argument contrary to the plain language of the statute, but it collapses the clear statutory distinction between the two periods before and after a rule takes effect.

The remaining arguments that Defendants repeat from Becerra are likewise unavailing here. With respect to Defendants' claim that limiting Section 705 to situations where the effective date of a regulation has not passed would unduly hamper its ability to use this authority, Plaintiffs persuasively argue that the challenges to the Rule in the District of Wyoming prove the fallacy of

this argument. There, the industry groups moved quickly (in one case, even before the final Rule was published in the Federal Register) to initiate litigation challenging the validity of the Rule and seek a preliminary injunction. In response, the Bureau appeared in those actions to defend the Rule and, ultimately, the court declined to issue a preliminary injunction before the effective date passed. As Congress envisioned, the Bureau had ample time between the filing of the District of Wyoming lawsuits and the Rule's effective date to issue a stay pursuant to Section 705, but it chose not to do so.

Defendants' policy argument that the Court should construe Section 705 to include "compliance dates" because Section 705 is meant to allow an agency to maintain the status quo pending judicial review is equally unpersuasive. Indeed, Defendants' position undercuts regulatory predictability and consistency. See Price, 697 F.3d at 830 (formal rulemaking exists in order to provide "notice and predictability to regulate parties"). After years of developing the Rule and working with the public and industry stakeholders, the Bureau's suspension of the Rule five months after it went into effect plainly did not "maintain the status quo." To the contrary, it belatedly disrupted it. Regulated entities with large operations had already needed to make concrete preparations after the Rule had not only become final but had actually gone into effect. The uncertainty that can arise from this kind of sudden agency reversal of course is illustrated by its impact on the regulated entities here. As Intervenor Western Energy Alliance explained to the Court at oral argument, many of the companies it represents within the gas and energy industry stopped moving toward compliance with the Rule based, in significant part, on Defendants' issuance of the Postponement Notice. In arguing against a remedy of vacatur (discussed more fully below), Intervenor Western Energy Alliance contended that some large regulated entities would be less likely to be able to meet the compliance deadline of January 17, 2018 because they relied on Defendants' postponement.

Finally, Defendants argue that the term "effective date" in Section 705 must be interpreted broadly based on its context in the overall scheme of the APA. Under their interpretation, the definition of effective date in Section 705 must be broader than the definition in Section 553(d) of the APA, which applies to rulemaking, because Section 705 applies more broadly to all agency

action rather than just rulemaking. See 5 U.S.C. § 705 (allowing an agency to postpone "action taken by it"); 5 U.S.C. § 551(13) (defining agency action to include "the whole or a part of an agency rule, order, license, sanction, relief, or the equivalent or denial thereof, or failure to act"). Their argument is not persuasive. While Section 705 allows the postponement of the effective date of a broader range of agency actions than a complete rule, such as a part of a rule or a license, and would have allowed the agency lawfully to postpone certain parts of the Rule, rather than its entirety, had it done so before the effective date of January 17, 2017, that possibility does not alter the plain meaning of "effective date."

E. APA's Notice-and-Comment Requirements

Plaintiffs also argue that Defendants violated the APA's notice-and-comment requirements by effectively repealing the Rule without engaging in the process for obtaining comment from the public. Sections 553(b) and (c) of the APA set forth the notice-and-comment requirements for agency "rule making." 5 U.S.C. § 553. "Rule making means agency process for formulating, amending, or repealing a rule." 5 U.S.C. § 551(5). The retraction of a duly-promulgated regulation requires compliance with the APA's notice-and-comment procedures. See Envt'l Def. Fund, Inc. v. Gorsuch, 713 F.3d 802, 817 (D.C. Cir. 1983); Clean Air Council v. Pruitt, 2017 WL 2838112, at *11 (D.C. Cir. July 3, 2017); Perez v. Mortg. Bankers Ass'n, __ U.S. __ 135 S. Ct. 1199, 1206 (2015); F.C.C. v. Fox Television Stations, Inc., 556 U.S. 502, 515 (2009); Nat. Res. Def. Council v. Envtl. Prot. Agency, 683 F.3d 752, 761 (3d Cir. 1982).

Defendants respond that Section 705 does not refer to notice-and-comment requirements. Without citing any authority, Defendants also argue that notice-and-comment would impede its ability to act swiftly to maintain the status quo, as Congress envisioned when it crafted the Section 705 authority. Defendants rely on Sierra Club v. Jackson, 833 F. Supp. 2d 11, 28 (D.D.C. 2012), which held that the section 705 delay notice did not constitute substantive rulemaking. The Court has already rejected this argument in Becerra, explaining that in Sierra Club the agency properly invoked section 705 *before* the rule's effective date. Therefore, the postponement of the rule there was not effectively a repeal, unlike here. The APA does not permit an agency to

> guide a future rule through the rulemaking process, promulgate a

> final rule, and then effectively repeal it, simply by indefinitely postponing its operative date. The APA specifically provides that the repeal of a rule is rulemaking subject to rulemaking procedures.

Nat. Res. Def. Council, 683 F.2d at 762. By now only belatedly following the requisite notice-and-comment procedures to issue a proposed rule that postpones the compliance dates for six months after first trying to bypass those procedures, Defendants' actions speak louder than words, tacitly conceding that the Postponement Notice was improper.

As the Court observed in Becerra, the policy underlying the statutory requirement of notice-and-comment is equally applicable to the repeal of regulations as to their adoption. See Consumer Energy Council of Am. v. Fed. Energy Regulatory Comm'n, 673 F.2d 425, 446 (D.C. Cir. 1982) ("The value of notice and comment prior to repeal of a final rule is that it ensures that an agency will not undo all that it accomplished through its rulemaking without giving all parties an opportunity to comment on the wisdom of repeal.").

F. Bureau's Justification under Section 705

In addition to contending that Defendants exceeded their power under Section 705, Plaintiffs also argue that the Postponement Notice was unlawful because it was arbitrary and capricious and did not meet the additional statutory requirements of "pending litigation" and "justice so requires."

1. Reconsideration of the Rule

First, Plaintiffs argue that one of the Bureau's stated justifications for the Postponement Notice was to delay compliance while it "reviews and reconsiders the Rule." 82 Fed. Reg. 27,431. Citing Sierra Club, Plaintiffs argue that invoking Section 705 for this purpose was arbitrary and capricious because Section 705 is not applicable where "[t]he purpose and effect of the [Postponement] Notice plainly are to stay the rules pending reconsideration, not litigation." 833 F. Supp. 2d at 33. Defendants respond that there is nothing in Section 705 that prohibits the Bureau from having two reasons for postponing a regulation (in this case, "pending judicial review" and agency reconsideration).

As in Sierra Club, however, Defendants have merely paid "lip service" to the pending judicial review in the District of Wyoming. See Sierra Club, 833 F. Supp. 2d at 34. Rather than

justify the Section 705 postponement based on the litigation in the District of Wyoming cases, the Postponement Notice reiterated that the Bureau believed the Rule had been properly promulgated and merely stated, without any specificity, that "the petitioners have raised serious questions concerning the validity of certain provisions of the Rule." 82 Fed. Reg. 27,431. Furthermore, similar to the stay the defendants sought in Becerra, the Bureau requested and received a 90 day extension to the briefing schedule in the District of Wyoming litigation, relying on the Postponement Notice and future administrative review as justifications for the extension. These actions run counter to the Bureau's statement that pending judicial review in the District of Wyoming litigation was the true reason for the Postponement Notice. While there is no prohibition against having more than one justification for invoking Section 705, provided that one of them meets the statutory requirements, Defendants must be able to show that they properly invoked the statutorily required ground of "pending judicial review." Defendants have not done so here.

2. "Justice So Requires" and the Failure to Consider the Foregone Benefits

Alternatively, Plaintiffs argue that the Bureau's decision was arbitrary and capricious because it only took into account the costs to the oil and gas industry of complying with the Rule and completely ignored the benefits that would result from compliance. It is a fundamental principle of the APA that an agency's decision is arbitrary when it "entirely failed to consider an important aspect of the problem." Motor Vehicles Mfs., 463 U.S. at 43. Although an agency is entitled to change its policy positions, it has an obligation to adequately explain the reason for the change and its rejection of its earlier factual findings. See Organized Vill. of Kake v. U.S. Dep't of Ag., 795 F.3d 956, 966-67 (9th Cir. 2015) (en banc) (citing FCC v. Fox Television Stations, Inc., 556 U.S. 502, 515-16 (2009)).

Here, based on the rationale stated in the Postponement Notice, the Bureau entirely failed to consider the benefits of the Rule, such as decreased resource waste, air pollution, and enhanced public revenues. Defendants' argument that Section 705 "places no limitations on an agency's determination of what 'justice so requires,'" (Defs.' Opp. at 13), would render that language mere

surplusage, contrary to a basic rule of statutory construction. If the words "justice so requires" are to mean anything, they must satisfy the fundamental understanding of justice: that it requires an impartial look at the balance struck between the two sides of the scale, as the iconic statue of the blindfolded goddess of justice holding the scales aloft depicts. Merely to look at only one side of the scales, whether solely the costs or solely the benefits, flunks this basic requirement. As the Supreme Court squarely held, an agency cannot ignore "an important aspect of the problem." Motor Vehicles Mfs., 463 U.S. at 43. Without considering both the costs *and* the benefits of postponement of the compliance dates, the Bureau's decision failed to take this "important aspect" of the problem into account and was therefore arbitrary. Furthermore, Defendants' argument that they can ignore the benefits of the Rule because they do not materialize until 2018 is a self-fulfilling prophecy because, according to the agency's own cost-benefit analysis made in promulgating the Rule, those benefits will be reaped starting in January 2018 and outweigh the costs—*unless* the agency prevents compliance with that deadline as it sought to do through the unlawfully issued Postponement Notice.

Instead of taking into account the benefits of the Rule when issuing the Postponement Notice, Defendants premised their action on the grounds that the costs were not justified because circumstances had changed between the time the Rule was developed and finalized and the time it was postponed in June 2017. Defendants contend that the relevant changed circumstances include the completely foreseeable and foreseen fact that the January 17, 2018 compliance deadline was becoming more urgent, as well as the District of Wyoming having "expressed misgivings with the Rule"—even though it denied the challengers' motion for a preliminary injunction—and the President issuing an executive order directing the executive agencies to re-evaluate regulations that affect the energy industry. For their part, Plaintiffs contend that the only thing that actually changed before issuance of the Postponement Notice was "the agency's position with respect to whether those costs are justified." (Grps' Opp. at 11).

New presidential administrations are entitled to change policy positions, but to meet the requirements of the APA they must give reasoned explanations for those changes and "address [the] prior factual findings" underpinning a prior regulatory regime. See Organized Vill. of Kake,

795 F.3d at 966. Significantly, Defendants have not argued that the Rule's promulgation was based on inaccurate facts or faulty cost-benefit studies. Indeed, in support of postponing the compliance date because of a new concern with the costs to the oil and gas industry, the Postponement Notice relied on precisely the same Regulatory Impact Analysis that it had previously relied upon to support adoption of the Rule and justify its costs, which showed that the benefits substantially outweighed the costs. Thus, it supported the Postponement Notice by only considering one side of the equation. As the Supreme Court held, "a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy." Fox Television Stations, 556 U.S. at 515-16. Defendants have presented no "reasoned explanation" for the agency's action and "[i]t would be arbitrary or capricious to ignore such matters." Id.[5] Defendants' failure to consider the benefits of compliance with the provisions that were postponed, as evidenced by the face of the Postponement Notice, rendered their action arbitrary and capricious and in violation of the APA.

3. "Justice So Requires" and the Preliminary Injunction Test

Finally, Plaintiffs argue that the Bureau was required to apply the four-part preliminary injunction test to show that "justice so requires" postponing compliance under Section 705, which the Bureau did not reference or apply in the Postponement Notice. Plaintiffs rely on Sierra Club in which the court found that the EPA's invocation of Section 705 was arbitrary and capricious based on EPA's failure to apply the four-part preliminary injunction test. See Sierra Club, 833 F. Supp. 2d at 30-31. As the court in Sierra Club noted, the legislative history of Section 705 provides some support for this interpretation:

> This Section permits either agencies or courts, if the proper showing be made, to maintain the status quo . . . The authority granted is equitable and should be used by both agencies and courts to prevent irreparable injury or afford parties an adequate judicial remedy.

[5] While Defendants' failure to fully consider all important aspects of postponing the compliance deadlines when issuing the Postponement Notice was arbitrary and capricious, this result does not necessarily resolve the issue raised by *amicus* The Institute for Policy Integrity that Defendants were required to support their change in policy with a full cost-benefit analysis. Because the Postponement Notice was arbitrary and capricious for its failure to consider the foregone benefits of compliance at all, the Court need not resolve this question.

Id. at 31 (quoting Administrative Procedure Act, Pub. L. 1944-46, S. Doc. 248 at 277 (1946) (describing the intent of 5 U.S.C. § 1009(d), the prior version of Section 705)). Sierra Club reasoned that there was nothing in the text of Section 705 or its legislative history that suggested that the standard for a stay pending judicial review differs between agencies and courts. Sierra Club, 833 F. Supp. 2d at 30-31.

Defendants disagree that they were required to consider the four-part preliminary injunction test when issuing the Postponement Notice pursuant to Section 705 and that Sierra Club was wrongly decided. Defendants point out that the text of Section 705 requires neither a court nor an agency to make findings about the four preliminary injunction factors when issuing a Section 705 stay:

> When *an agency* finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, *the reviewing court*, including the court to which a case may be taken on appeal from or on application for certiorari or other writ to a reviewing court, may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.

5 U.S.C. § 705 (emphasis added). They argue that the text of Section 705 only requires an agency to base its decision to implement a stay on a finding that "justice so requires," and that the next sentence, which references certain factors of the preliminary injunction test, only refers to court-issued stays. In response to the legislative history noted by Plaintiffs and the court in Sierra Club, Defendants point to subsequent legislative history from 1946 that they argue more closely tracks the statutory language and supports their position that Section 705 does not require an agency to weigh the four factors of the preliminary injunction test when determining if "justice so requires":

> [Section 705] provides that any agency may itself postpone the effective date of its action pending judicial review, or, upon conditions and as may be necessary to prevent irreparable injury, reviewing courts may postpone the effective date of contested action or preserve the status quo pending conclusion of judicial review proceedings.

S. Doc. 248 at 369 (1946).

Finally, Defendants argue that requiring agencies to weigh the four factors of the

preliminary injunction test is impractical. For instance, an agency would be required to find that a party who is challenging a regulation is likely to succeed on the merits, which would undermine the agency's litigation position and hinder its defense. Defendants claim that the test is particularly troubling in situations where an agency is reconsidering a regulation, as the Bureau is doing here, because it essentially forces an agency to admit error in order to provide relief to regulated parties pending judicial review and reconsideration, even though agencies can reconsider regulations for policy reasons without admitting error.

The Parties and *amici* vigorously contest whether Defendants were required to satisfy the four-factor preliminary injunction test when they relied upon Section 705 to postpone the compliance date under the justification that "justice so requires." The plain language of the statute leaves room to dispute whether such an analysis is required, and the legislative history provides limited and not entirely consistent evidence of Congress' intent. The statue is clear, however, that a postponement requires the agency to make a determination that "justice so requires." Because of the complete failure to consider the foregone benefits of compliance, Defendants have failed to meet the "justice so requires" requirement of Section 705. Therefore, the Court does not reach the issue of whether Defendants' action was arbitrary and capricious for their failure to utilize the preliminary injunction test.

V. REMEDY

Having concluded that Defendants violated the APA when the Bureau issued the Postponement Notice, the Court must consider the appropriate remedy. Plaintiffs have requested declaratory relief and vacatur of the Postponement Notice.

Vacatur is the standard remedy for violation of the APA. See Se. Alaska Conservation Council v. U.S. Army Corps of Eng'rs, 486 F.3d 638, 654 (9th Cir. 2007), rev'd on other grounds sub nom., Coeur Alaska v. Se. Alaska Conservation Council, 557 U.S. 261 (2009); Klamath-Siskiyou Wildlands Center v. Nat'l Oceanic and Atmospheric Admin., 109 F. Supp. 3d 1238, 1241 (N.D. Cal. 2015) (citations omitted). To determine whether to make an exception to the usual remedy of vacatur, the Court considers two factors: (1) "how serious the agency's errors are," and (2) "the disruptive consequences of an interim change that may itself be changed." See

Cal. Cmtys. Against Toxics v. Envtl. Prot. Agency, 688 F.3d 989, 992 (9th Cir. 2012) (quoting Allied-Signal, Inc. v. U.S. Nuclear Regulatory Comm'n, 988 F.3d 146, 150-51 (D.C. Cir. 1993)).

As to the first factor, the Bureau's errors in illegally invoking Section 705 to issue the Postponement Notice and circumvent the APA's notice-and-comment requirements were serious. See Nat. Res. Defense Council v. Envtl. Prot. Agency, 489 F.3d 1364, 1374 (D.C. Cir. 2007) ("The agency's errors could not be more serious insofar as it acted unlawfully, which is more than sufficient reason to vacate the rules."). Courts generally only remand without vacatur when the errors are minor procedural mistakes, such as failing to publish certain documents in the electronic docket of a notice-and-comment rulemaking. See Cal. Cmtys., 688 F.3d at 992. Thus, this factor heavily favors vacating the Postponement Notice.

The second factor is the potential disruptive consequences that would arise from vacatur. Defendants argue that vacatur would require regulated entities to spend approximately $114 million dollars to achieve compliance. Requiring these entities to spend that much money is unnecessarily disruptive and inequitable, they contend, because the Bureau is planning to lawfully suspend the Rule and ultimately revise or rescind it. They also note that the court presiding over the District of Wyoming challenge to the Rule expects to issue its decision before the January 17, 2018 compliance date, which could mean that the Rule will be invalidated, even though the court denied a preliminary injunction in part based on plaintiffs in that case not having shown a sufficient likelihood of success at that time. Intervenor Western Energy Alliance also contends that some of its members relied on the Postponement Notice and the District of Wyoming litigation to defer compliance efforts, so it may well be impossible at this point for at least some of the larger-scale regulated entities to meet the January 17, 2018 compliance deadline.

Notably, the rare exceptions to vacatur involve irreparable and severe disruptive consequences that went far beyond the potential disruptive consequences that Defendants raise here. Thus, the Ninth Circuit declined to vacate illegally promulgated regulations where vacatur could result in the extinction of an already endangered species. See Idaho Farm Bureau Fed. v. Babbit, 58 F.3d 1392, 1405-06 (9th Cir. 1995). And it denied vacatur that would have resulted in rolling blackouts affecting thousands, if not millions of people, more air pollution, and disastrous

economic effects. See Cal. Comtys., 688 F.3d at 994.

By contrast, as Plaintiffs point out, vacating the Postponement Notice and reinstating the Rule is predicted to result in a net positive financial and environmental benefit, according to the agency's analysis, because compliance will reduce the waste of public resources, curb the emission of harmful environmental pollutants, increase royalty payments, and, for many of the new requirements relating to reducing the waste of valuable resources, pay for itself over time. Moreover, vacating the Postponement Notice would merely put the regulated parties back in the position of working toward compliance. If some of the regulated entities of the oil and gas industry will not be able to meet the January 17, 2018 compliance date because they suspended compliance efforts after the District of Wyoming denied the preliminary injunction and the Bureau issued the Postponement Notice, that is a problem to some extent of their own making and is not a sufficient reason for the Court to decline vacatur. This lawsuit by California and New Mexico has been on the public docket since July 5, only 20 days after the Bureau issued the Postponement Notice, and the related case was filed five days later. As evidenced by its trade association's intervention in this case, the oil and gas industry was well aware that the Postponement Notice was potentially vulnerable to invalidation. Moreover, denying the standard remedy of vacatur based on less severe disruptive consequences than those previously recognized as warranting keeping the unlawful regulation in place could be viewed as a free pass for agencies to exceed their statutory authority and ignore their legal obligations under the APA, making a mockery of the statute.

This is not like the situation in Becerra where the agency had already finalized a new rule and vacatur would only return the parties to the previous regulatory regime for a short one week period. Under those very unusual circumstances, vacating the illegal postponement of the regulation was not warranted. In this case, however, the Bureau has not yet promulgated a replacement for the Rule. Although the Bureau intends to engage in actual rulemaking to postpone the Rule's compliance dates and issue a proposed rule for public notice and comment, that proposal is still under review within the agency and by the Office of Management and Budget ("OMB"). Furthermore, once promulgated, Defendants acknowledged at oral argument that the

Bureau would engage in a 30-day notice-and-comment period. Indeed, if the Bureau receives "significant" comments to the proposed rule, as seems likely given the numerous comments it originally received in favor of as well as against the Rule that it seeks to functionally suspend, it will need to provide written responses, which will take additional time. See Am. Mining Congress v. Envtl. Prot. Agency, 965 F.2d 759, 771 (9th Cir. 1992). After considering and responding to any significant comments, the agency must then draft the final rule and, most likely, seek approval of the rule from OMB. See Executive Order 12,866. After OMB has approved the agency's draft final rule, the agency must then publish the final rule in the Federal Register, and it will not become effective until at least 30 days after its publication. 5 U.S.C. § 553(d). At the hearing on Plaintiffs' motions, Defendants acknowledged that finalizing that new proposed rule would take at least two months. Defendants have also informed the Court that they intend to propose another round of rulemaking to revise or rescind the Rule, but the Bureau is still drafting that proposed rule and it has not yet been circulated for review within the agency or OMB. Given the time-intensive steps required to move a draft rule forward to final publication and the additional period of 30 days before it comes effective, any such rule revising or rescinding the Rule is unlikely to go into effect for a number of months. In the end, there is no certainty that either proposed rulemaking will survive potential legal challenge, given the litigation history of this Rule. Thus, application of the general rule in favor of vacatur is appropriate here.

VI. CONCLUSION

For the reasons set forth above, the Court GRANTS Plaintiffs' motions for summary judgment and vacates the Postponement Notice.

IT IS SO ORDERED.

Dated: October 4, 2017

ELIZABETH D. LAPORTE
United States Magistrate Judge

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4310-84P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 3160 and 3170

[17X.LLWO310000.L13100000.PP0000]

RIN 1004-AE54

Waste Prevention, Production Subject to Royalties, and Resource Conservation; Delay and Suspension of Certain Requirements

AGENCY: Bureau of Land Management, Interior.

ACTION: Proposed rule.

SUMMARY: On November 18, 2016, the Bureau of Land Management (BLM) published in the *Federal Register* a final rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" (2016 final rule). The BLM is now proposing to temporarily suspend or delay certain requirements contained in the 2016 final rule until January 17, 2019. The BLM is currently reviewing the 2016 final rule and wants to avoid imposing temporary or permanent compliance costs on operators for requirements that may be rescinded or significantly revised in the near future.

DATES: Send your comments on this proposed rule to the BLM on or before [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. As explained later, the BLM is also requesting that the Office of Management and Budget (OMB) extend the control number (1004-0211) for the 24 information collection activities that would continue in this proposed rule. If you wish to comment on this request, please note that such comments should be sent directly to the OMB, and that the

OMB is required to make a decision concerning the collection of information contained in this proposed rule between 30 and 60 days after publication of this document in the *Federal Register*. Therefore, a comment to the OMB on the proposed information collection revisions is best assured of being given full consideration if the OMB receives it by [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

ADDRESSES: *Mail:* U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134LM, 1849 C St., N.W., Washington, D.C. 20240, Attention: 1004-AE52.

Personal or messenger delivery: U.S. Department of the Interior, Bureau of Land Management, 20 M Street, S.E., Room 2134 LM, Washington, D.C. 20003, Attention: Regulatory Affairs.

Federal eRulemaking Portal: https://www.regulations.gov. In the Searchbox, enter "RIN 1004-AE54" and click the "Search" button. Follow the instructions at this website.

Comments on the information collection burdens: *Fax:* Office of Management and Budget (OMB), Office of Information and Regulatory Affairs, Desk Officer for the Department of the Interior, fax 202–395–5806.

Electronic mail: OIRA_Submission@omb.eop.gov. Please indicate ‘‘Attention: OMB Control Number 1004–0211,’’ regardless of the method used to submit comments on the information collection burdens. If you submit comments on the information collection burdens, you should provide the BLM with a copy, at one of the addresses shown earlier in this section, so that we can summarize all written comments and address them in the final rule preamble.

FOR FURTHER INFORMATION CONTACT: Catherine Cook, Acting Division Chief, Fluid Minerals Division, 202-912-7145, or ccook@blm.gov, for information regarding the substance of this proposed rule or information about the BLM's Fluid Minerals program. For questions relating to regulatory process issues, contact Faith Bremner, Regulatory Analyst, at 202-912-7441, or fbremner@blm.gov. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service (FRS) at 1-800-877-8339, 24 hours a day, 7 days a week, to leave a message or question with the above individuals. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

I. Public Comment Procedures

If you wish to comment on this proposed rule, you may submit your comments by any of the methods described in the "ADDRESSES" section.

Please make your comments on the proposed rule as specific as possible, confine them to issues pertinent to the proposed rule, and explain the reason for any changes you recommend. Where possible, your comments should reference the specific section or paragraph of the proposal that you are addressing. The BLM is not obligated to consider or include in the Administrative Record for the final rule comments that we receive after the close of the comment period (see "DATES") or comments delivered to an address other than those listed above (see "ADDRESSES").

Comments, including names and street addresses of respondents, will be available for public review at the address listed under "ADDRESSES: Personal or messenger delivery" during regular hours (7:45 a.m. to 4:15 p.m.), Monday through Friday, except holidays. Before including your address, telephone number, email address, or other personal identifying information in your comment, be advised that your entire comment--including your personal identifying information--may be made publicly available at any time. While you can ask us in your comment to withhold from public review your personal identifying information, we cannot guarantee that we will be able to do so.

II. Background

The BLM's onshore oil and gas management program is a major contributor to our nation's oil and gas production. The BLM manages more than 245 million acres of Federal land and 700 million acres of subsurface estate, making up nearly a third of the nation's mineral estate. In fiscal year (FY) 2016, sales volumes from Federal onshore production lands accounted for 9 percent of domestic natural gas production, and 5 percent of total U.S. oil production. Over $1.9 billion in royalties were collected from all oil, natural gas, and natural gas liquids transactions in FY 2016 on Federal and Indian Lands. Royalties from Federal lands are shared with States. Royalties from Indian lands are collected for the benefit of the Indian owners.

In response to oversight reviews and a recognition of increased flaring from Federal and Indian leases, the BLM developed a final rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation," which was published in the *Federal Register* on November 18, 2016. See 81 FR 83008 (Nov. 18, 2016). The rule replaced the BLM's existing policy at that time, Notice to Lessees and Operators of

Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A). The 2016 final rule was intended to: Reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases; clarify when produced gas lost through venting, flaring, or leaks is subject to royalties; and clarify when oil and gas production may be used royalty-free on-site. The 2016 final rule became effective on January 17, 2017. Many of the final rule's provisions are to be phased in over time, and are to become operative on January 17, 2018.

Immediately after the 2016 final rule was issued, industry groups and States with significant BLM-managed Federal and Indian minerals filed petitions for judicial review. The petitioners in this litigation are the Western Energy Alliance (WEA), the Independent Petroleum Association of America, the State of Wyoming, the State of Montana, the State of North Dakota, and the State of Texas. This litigation has been consolidated and is now pending in the U.S. District Court for the District of Wyoming. *Wyoming v. U.S. Dep't of the Interior*, Case No. 2:16-cv-00285-SWS (D. Wyo.); *W. Energy All. v. Zinke*, Case No. 16-cv-280-SWS (D. Wyo.). Petitioners assert that the BLM was arbitrary and capricious in promulgating the 2016 final rule and that the rule exceeds the BLM's statutory authority. Shortly after filing petitions for judicial review, petitioners filed motions for a preliminary injunction, seeking a stay of the rule pending the outcome of the litigation. These motions were denied by the court on January 16, 2017, and the rule went into effect the following day. Although the court denied the motions for a preliminary injunction, it did express concerns that the BLM may have "usurp[ed]" the authority of the Environmental Protection Agency (EPA) and the States

under the Clean Air Act, and questioned whether it was appropriate for the 2016 final rule to be justified based on its environmental and societal benefits, rather than on its resource conservation benefits alone. The next stage in the litigation will be the court's consideration of the merits of the petitioner's claims. It is possible that the court's decision on these claims could result in the 2016 final rule being overturned. On June 15, 2017, the Department of the Interior (Department) issued a Federal Register notice, pursuant to 5 U.S.C. 705, postponing the January 2018 compliance dates of the 2016 final rule pending judicial review. 82 FR 27430 (June 15, 2017).

In the Regulatory Impact Analysis (RIA) for the 2016 final rule, the BLM estimated that the requirements of the 2016 final rule would impose compliance costs, not including potential cost savings for product recovery, of approximately $114 million to $279 million per year (2016 RIA at 4). The BLM had concluded that, while many of the requirements were consistent with EPA regulations for new sources, current industry practice, or similar to the requirements found in some existing State regulations, the 2016 final rule would be an economically significant rule with estimated costs and benefits exceeding $100 million per year (2016 RIA at 138). Comments received by many oil and gas companies and trade associations representing members of the oil and gas industry suggested that the BLM's proposed and final rules were unnecessary and would cause substantial harm to the industry. During the litigation following the issuance of the 2016 final rule, the petitioners argued that the BLM underestimated the compliance costs of the final rule and that the costs would drive the industry away from Federal and Indian lands, thereby reducing royalties and harming State and tribal economies. The petitioners also argued that the final rule would cause marginal wells to be shut-in, thereby ceasing

production and reducing economic benefits to local, State, tribal, and Federal governments. The BLM is concerned that the RIA for the 2016 final rule may have underestimated costs and overestimated benefits, and is therefore presently reviewing that analysis for potential inaccuracies. In any event, the RIA for the 2016 rule indicates that the rule poses a substantial burden on industry, particularly those requirements that are set to become effective on January 17, 2018.

Since late January 2017, the President has issued several Executive Orders that necessitate a review of the 2016 final rule by the Department. On January 30, 2017, the President issued Executive Order 13771, entitled, "Reducing Regulation and Controlling Regulatory Costs," which requires Federal agencies to take proactive measures to reduce the costs associated with complying with Federal regulations. In addition, on March 28, 2017, the President issued Executive Order 13783, entitled, "Promoting Energy Independence and Economic Growth." Section 7(b) of Executive Order 13783 directs the Secretary of the Interior to review four specific rules, including the 2016 final rule, for consistency with the policy articulated in section 1 of the Order and, "if appropriate," to publish proposed rules suspending, revising, or rescinding those rules. Among other things, section 1 of Executive Order 13783 states that "[i]t is in the national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation."

To implement Executive Order 13783, Secretary of the Interior Ryan Zinke issued Secretarial Order No. 3349, entitled, "American Energy Independence" on March 29, 2017, which, among other things, directs the BLM to review the 2016 final rule to

determine whether it is fully consistent with the policy set forth in section 1 of Executive Order 13783. The BLM conducted an initial review of the 2016 final rule and found that it appears to be inconsistent with the policy in section 1 of Executive Order 13783. The BLM found that some provisions of the rule appear to add regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation. Following up on its initial review, the BLM is currently reviewing the 2016 final rule to develop an appropriate proposed revision—to be promulgated through notice-and-comment rulemaking—that would propose to align the 2016 final rule with the policies set forth in section 1 of Executive Order 13783.

III. Discussion of the Proposed Rule

A. Summary and Request for Comment

Today, the BLM is proposing to temporarily suspend or delay certain requirements contained in the 2016 final rule until January 17, 2019. The BLM is currently reviewing the 2016 final rule, as directed by the aforementioned Executive Orders and by Secretarial Order No. 3349. The BLM wants to avoid imposing temporary or permanent compliance costs on operators for requirements that might be rescinded or significantly revised in the near future. The BLM also wishes to avoid expending scarce agency resources on implementation activities (internal training, operator outreach/education, developing clarifying guidance, etc.) for such potentially transitory requirements.

For certain requirements in the 2016 final rule that have yet to be implemented, this proposed rule would temporarily postpone the implementation dates until January 17, 2019, or for one year. For certain requirements in the 2016 final rule that are currently in

effect, this proposed rule would temporarily suspend their effectiveness until January 17, 2019. A detailed discussion of the proposed suspensions and delays is provided below. The BLM has attempted to tailor the proposed rule so as to target the requirements of the 2016 final rule for which immediate regulatory relief appears to be particularly justified. Although the requirements of the 2016 final rule that would not be suspended under the proposed rule may ultimately be revised in the near future, the BLM is not proposing to suspend them because it does not, at this time, believe that suspension is necessary.

The BLM promulgated the 2016 final rule, and now proposes to suspend and delay certain provisions of that rule, pursuant to its authority under the following statutes: The Mineral Leasing Act of 1920 (30 U.S.C. 188-287), the Mineral Leasing Act for Acquired Lands (30 U.S.C. 351-360), the Federal Oil and Gas Royalty Management Act (30 U.S.C. 1701-1758), the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1701-1785), the Indian Mineral Leasing Act of 1938 (25 U.S.C. 396a-g), the Indian Mineral Development Act of 1982 (25 U.S.C. 2101-2108), and the Act of March 3, 1909 (25 U.S.C. 396). See 81 FR 83008 and 83019-83021 (Nov. 18, 2016). These statutes authorize the Secretary of the Interior to promulgate such rules and regulations as may be necessary to carry out the statutes' various purposes.[1] The Federal and Indian mineral leasing statutes share a common purpose of promoting the development of Federal and Indian oil and gas resources for the financial benefit of the public and Indian mineral owners.[2] In order to ensure that the development of Federal and Indian oil and gas resources will not be unnecessarily hindered by regulatory burdens, the BLM is

[1] 30 U.S.C. 189 (MLA); 30 U.S.C. 359 (MLAAL); 30 U.S.C. 1751(a) (FOGRMA); 43 U.S.C. 1740 (FLPMA); 25 U.S.C. 396d (IMLA); 25 U.S.C. 2107 (IMDA); 25 U.S.C. 396.

[2] *See, e.g., California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961) (noting that the MLA was intended to promote wise development of . . . natural resources and to obtain for the public a reasonable financial return on assets that 'belong' to the public.").

exercising its inherent authority[3] to reconsider the 2016 final rule. The suspension of requirements proposed today is a part of the BLM's reconsideration process.

The BLM seeks comment on this proposed rule. Issues of particular interest to the BLM include the necessity of the proposed suspensions and delays, the costs and benefits associated with the proposed suspensions and delays, and whether suspension of other requirements of the 2016 rule is warranted. The BLM is also interested in the appropriate length of the proposed suspension and delays and would like to know whether the period should be longer or shorter (e.g., six months, 18 months, or 2 years). The BLM has allowed a 30-day comment period for this proposed rule, which the BLM believes will afford the public a meaningful opportunity to comment. This proposed rule is a straightforward suspension and delay of regulatory provisions that were (in a proposed form) themselves recently the object of public comment procedures. Because this proposal is a narrow one, involving a simple and temporary suspension and delay of regulatory provisions with which interested parties are likely already familiar, the BLM believes that the 30-day comment period is appropriate.

B. Section-by-Section Discussion

43 CFR 3162.3-1(j) - Drilling applications and plans.

In the 2016 final rule, the BLM added a paragraph (j) to 43 CFR 3162.3-1, which presently requires that when submitting an Application for Permit to Drill (APD) for an oil well, an operator must also submit a waste-minimization plan. Submission of the plan is required for approval of the APD, but the plan is not itself part of the APD, and the terms of the plan are not enforceable against the operator. The purpose of the waste-

[3] *See Ivy Sports Med., LLC v. Burwell*, 767 F.3d 81, 86 (D.C. Cir. 2014) (noting "oft-repeated" principle that the "power to reconsider is inherent in the power to decide").

minimization plan is for the operator to set forth a strategy for how the operator will comply with the requirements of 43 CFR subpart 3179 regarding the control of waste from venting and flaring from oil wells.

The waste-minimization plan must include information regarding: The anticipated completion date(s) of the proposed oil well(s); a description of anticipated production from the well(s); certification that the operator has provided one or more midstream processing companies with information about the operator's production plans, including the anticipated completion dates and gas production rates of the proposed well or wells; and identification of a gas pipeline to which the operator plans to connect. Additional information is required when an operator cannot identify a gas pipeline with sufficient capacity to accommodate the anticipated production from the proposed well, including: A gas pipeline system location map showing the proposed well(s); the name and location of the gas processing plant(s) closest to the proposed well(s); all existing gas trunklines within 20 miles of the well, and proposed routes for connection to a trunkline; the total volume of produced gas, and percentage of total produced gas, that the operator is currently venting or flaring from wells in the same field and any wells within a 20-mile radius of that field; and a detailed evaluation, including estimates of costs and returns, of potential on-site capture approaches.

In the RIA for the 2016 final rule, the BLM estimated that the administrative burden of the waste-minimization plan requirements would be roughly $1 million per year for the industry and $180,000 per year for the BLM (2016 RIA at 96 and 100). The BLM is currently reviewing the requirements of § 3162.3-1(j) in order to determine whether the burden it imposes on operators is necessary and whether this burden can be

reduced. The BLM is also evaluating whether there are circumstances in which compliance with § 3162.3-1(j) is infeasible because some of the required information is in the possession of a midstream company that is not in a position to share it with the operator. The BLM is considering narrowing the required information and is also considering whether submission of a State waste-minimization plan, such as those required by New Mexico and North Dakota, would serve the purpose of § 3162.3-1(j). While the BLM conducts this review and considers revising § 3162.3-1, the BLM does not believe that generating and reviewing lengthy, unenforceable waste-minimization plans is a prudent use of operator or BLM resources. The BLM is therefore proposing to suspend the waste minimization plan requirement of § 3162.3-1(j) until January 17, 2019.

This proposed rule would revise § 3162.3-1 by adding "Beginning January 17, 2019" to the beginning of paragraph (j). The rest of this paragraph would remain the same as in the 2016 final rule and the introductory paragraph is repeated in the proposed rule text only for context.

43 CFR 3179.7 – Gas capture requirement.

In the 2016 final rule, the BLM sought to constrain routine flaring through the imposition of a "capture percentage" requirement, requiring operators to capture a certain percentage of the gas they produce, after allowing for a certain volume of flaring per well. The capture-percentage requirement would become more stringent over a period of years, beginning with an 85 percent capture requirement (5,400 Mcf per well flaring allowable) in January 2018, and eventually reaching a 98 percent capture requirement (750 Mcf per well flaring allowable) in January 2026. An operator would choose

whether to comply with the capture targets on each of the operator's leases, units or communitized areas, or on a county-wide or state-wide basis.

In the RIA for the 2016 final rule, the BLM estimated that this requirement would impose costs of up to $162 million per year and generate cost savings from product recovery of up to $124 million per year, with both costs and cost savings increasing as the requirements increased in stringency (2016 RIA at 49).

The BLM is currently considering whether the capture-percentage requirement of § 3179.7 is unnecessarily complex and whether it will, in fact, be a significant improvement on the requirements of NTL-4A. The BLM is considering whether the NTL-4A framework can be applied in a manner that addresses any inappropriate levels of flaring, and whether market-based incentives (i.e., royalty obligations) could improve capture in a more straightforward and efficient manner. Finally, the BLM is considering whether the need for a complex capture-percentage requirement could be obviated through other BLM efforts to facilitate pipeline development. Rather than require operators to institute new processes and adjust their plans for development to meet a capture-percentage requirement that may be rescinded or revised as a result of the BLM's review, the BLM is proposing to delay for one year the compliance dates for § 3179.7's capture requirements. This delay would allow the BLM sufficient time to conduct notice-and-comment rulemaking to determine whether the capture percentage requirements should be rescinded or revised and would prevent operators from being unnecessarily burdened by regulatory requirements that are subject to change.

This proposed rule would revise the compliance dates in paragraphs (b), (b)(1) through (b)(4), and (c)(2)(i) through (vii) of § 3179.7 to begin January 17, 2019.

Paragraphs (c), (c)(1), and the introductory text of (c)(2) would remain the same as in the 2016 final rule and are repeated in the proposed rule text only for context.

43 CFR 3179.9 - Measuring and reporting volumes of gas vented and flared from wells.

Section 3179.9 requires operators to estimate (using estimation protocols) or measure (using a metering device) all flared and vented gas, whether royalty-bearing or royalty-free. This section further provides that specific requirements apply when the operator is flaring 50 Mcf or more of gas per day from a high-pressure flare stack or manifold, based on estimated volumes from the previous 12 months, or based on estimated volumes over the life of the flare, whichever is shorter. Beginning on January 17, 2018, if this volume threshold is met, § 3179.9(b) would require the operator to measure the volume of the flared gas, or calculate the volume of the flared gas based on the results of a regularly performed gas-to-oil ratio test, so as to allow the BLM to independently verify the volume, rate, and heating value of the flared gas.

In the RIA for the 2016 final rule, the BLM estimated that this requirement would impose costs of about $4 million to $7 million per year (2016 RIA at 52).

The BLM is presently reviewing § 3179.9 to determine whether the additional accuracy associated with the measurement and estimation required by § 3179.9(b) justifies the burden it would place on operators. The BLM is considering whether it would make more sense to allow the BLM to require measurement or estimation on a case-by-case basis, rather than imposing a blanket requirement on all operators. In order to avoid unnecessary compliance costs on the part of operators, the BLM is proposing to delay the compliance date in § 3179.9 until January 17, 2019.

This proposed rule would revise the compliance date in § 3179.9(b)(1). The rest of paragraph (b)(1) would remain the same as in the 2016 final rule and is repeated in the proposed rule text only for context.

43 CFR 3179.10 - Determinations regarding royalty-free flaring.

Section 3179.10(a) provides that approvals to flare royalty free that were in effect as of January 17, 2017, will continue in effect until January 17, 2018. The purpose of this provision was to provide a transition period for operators who were operating under existing approvals for royalty-free flaring. Because the BLM's review of the 2016 final rule could result in rescission or substantial revision of the rule, the BLM believes that terminating pre-existing flaring approvals in January 2018 would be premature and disruptive and would introduce needless regulatory uncertainty for operators with existing flaring approvals. The BLM is therefore proposing to extend the end of the transition period provided for in § 3179.10(a) to January 17, 2019.

This proposed rule would revise the date in paragraph (a) and replace "as of the effective date of this rule" with "as of January 17, 2017," which is the effective date of the 2016 final rule, for clarity. This proposed rule would not otherwise revise paragraph (a), but the rest of the paragraph would remain the same as in the 2016 final rule and is repeated in the proposed rule text only for context.

43 CFR 3179.101 - Well drilling.

Section 3179.101(a) requires that gas reaching the surface as a normal part of drilling operations be used or disposed of in one of four ways: (1) Captured and sold; (2) Directed to a flare pit or flare stack; (3) Used in the operations on the lease, unit, or communitized area; or (4) Injected. Section 3179.101(a) also specifies that gas may not

be vented, except under the circumstances specified in § 3179.6(b) or when it is technically infeasible to use or dispose of the gas in one of the ways specified above. Section 3179.101(b) states that gas lost as a result of a loss of well control will be classified as avoidably lost if the BLM determines that the loss of well control was due to operator negligence.

The BLM is currently reviewing § 3179.101 to determine whether it is necessary in light of current operator practices. The experience of BLM field office personnel indicates that operators would typically dispose of gas during well drilling consistent with § 3179.101(a). The primary effect of § 3179.101, therefore, may be to impose a regulatory constraint on operators in exceptional circumstances where the operator must make a case-specific judgment about how to safely and effectively dispose of the gas. The BLM is therefore proposing to suspend the effectiveness of § 3179.101 until January 17, 2019, while the BLM completes its review of § 3179.101 and decides whether to propose permanently revising or rescinding it through notice-and-comment rulemaking.

This proposed rule would add a new paragraph (c) making it clear that the operator must comply with § 3179.101 beginning January 17, 2019.

43 CFR 3179.102 - Well completion and related operations.

Section 3179.102 addresses gas that reaches the surface during well-completion, post-completion, and fluid-recovery operations after a well has been hydraulically fractured or refractured. It requires the gas to be used or disposed of in one of four ways: (1) Captured and sold; (2) Directed to a flare pit or stack, subject to a volumetric limitation in § 3179.103; (3) Used in the lease operations; or (4) Injected. Section 3179.102 specifies that gas may not be vented, except under the narrow circumstances

specified in § 3179.6(b) or when it is technically infeasible to use or dispose of the gas in one of the four ways specified above. Section 3179.102(b) provides that an operator will be deemed to be in compliance with its gas capture and disposition requirements if the operator is in compliance with the requirements for control of gas from well completions established under Environmental Protection Agency (EPA) regulations 40 CFR part 60, subparts OOOO or OOOOa regulations, or if the well is not a "well affected facility" under those regulations.

The BLM is currently reviewing § 3179.102 to determine whether it is necessary in light of current operator practices and the analogous EPA regulations in 40 CFR part 60, subparts OOOO and OOOOa. The experience of BLM field office personnel indicates that operators would typically dispose of gas during well completions and related operations consistent with § 3179.102(a). The BLM also suspects that most of the well completions and related operations that would otherwise be covered by § 3179.102 are actually exempted under § 3179.102(b). Considering current industry practice and the overlap with EPA regulations, the primary effect of § 3179.102 may be to generate confusion about regulatory compliance during well-drilling and related operations. The BLM is therefore proposing to suspend the effectiveness of § 3179.102 until January 17, 2019, while the BLM completes its review of § 3179.102 and decides whether to permanently revise or rescind it through notice-and-comment rulemaking.

This proposed rule would add a new paragraph (e) making it clear that operators must comply with § 3179.102 beginning January 17, 2019.

43 CFR 3179.201 - Equipment requirements for pneumatic controllers.

Section 3179.201 addresses pneumatic controllers that use natural gas produced

from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease. Section 3179.201 applies to such controllers if the controllers: (1) Have a continuous bleed rate greater than 6 standard cubic feet per hour (scf/hour) ("high-bleed" controllers); and (2) Are not covered by EPA regulations that prohibit the new use of high-bleed pneumatic controllers (40 CFR part 60, subparts OOOO or OOOOa), but would be subject to those regulations if the controllers were new, modified, or reconstructed sources. Section 3179.201(b) requires the applicable pneumatic controllers to be replaced with controllers (including, but not limited to, continuous or intermittent pneumatic controllers) having a bleed rate of no more than 6 scf/hour, subject to certain exceptions. Section 3179.201(d) requires that this replacement occur no later than January 17, 2018, or within 3 years from the effective date of the rule if the well or facility served by the controller has an estimated remaining productive life of 3 years or less.

In the RIA for the 2016 final rule, the BLM estimated that this requirement would impose costs of about $2 million per year and generate cost savings from product recovery of $3 million to $4 million per year (2016 RIA at 56).

The BLM is currently reviewing § 3179.201 to determine whether it should be revised or rescinded. The BLM is considering whether § 3179.201 is necessary in light of the analogous EPA regulations and the fact that operators are likely to adopt more efficient equipment in cases where it makes economic sense for them to do so. The BLM does not believe that operators should be required to make equipment upgrades to comply with § 3179.201 until the BLM has had an opportunity to review its requirements and revise them through notice-and-comment rulemaking. The BLM is therefore proposing

to delay the compliance date stated in § 3179.201 until January 17, 2019.

This proposed rule would revise the first sentence of paragraph (d) by replacing "no later than 1 year after the effective date of this section" with "by January 17, 2019." This proposed rule would also replace "the effective date of this section" with "January 17, 2017" the two times that it appears in the second sentence of paragraph (d). This proposed rule would not otherwise revise paragraph (d), but the rest of the paragraph would remain the same as in the 2016 final rule and is repeated in the proposed rule text only for context.

43 CFR 3179.202 - Requirements for pneumatic diaphragm pumps.

Section 3179.202 establishes requirements for operators with pneumatic diaphragm pumps that use natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease. It applies to such pumps if they are not covered under EPA regulations at 40 CFR part 60, subpart OOOOa, but would be subject to that subpart if they were a new, modified, or reconstructed source. For covered pneumatic pumps, § 3179.202 requires that the operator either replace the pump with a zero-emissions pump or route the pump exhaust to processing equipment for capture and sale. Alternatively, an operator may route the exhaust to a flare or low-pressure combustion device if the operator makes a determination (and notifies the BLM through a Sundry Notice) that replacing the pneumatic diaphragm pump with a zero-emissions pump or capturing the pump exhaust is not viable because: (1) A pneumatic pump is necessary to perform the function required; and (2) Capturing the exhaust is technically infeasible or unduly costly. If an operator makes this determination and has no flare or low-pressure combustor on-site, or routing to such a device would be

technically infeasible, the operator is not required to route the exhaust to a flare or low-pressure combustion device. Under § 3179.202(h), an operator must replace its covered pneumatic diaphragm pump or route the exhaust gas to capture or flare beginning no later than January 17, 2018.

In the RIA for the 2016 final rule, the BLM estimated that this requirement would impose costs of about $4 million per year and generate cost savings from product recovery of $2 million to $3 million per year (2016 RIA at 61).

The BLM is currently reviewing § 3179.202 to determine whether it should be rescinded or revised. Analogous EPA regulations apply to new, modified, and reconstructed sources, therefore limiting the applicability of § 3179.202. In addition, the BLM is concerned that requiring zero-emissions pumps may not conserve gas in some cases. The volume of royalty-free gas used to generate electricity to provide the power necessary to operate a zero-emission pump could exceed the volume of gas necessary to operate the pneumatic pump that the zero-emission pump would replace. The BLM does not believe that operators should be required to make equipment upgrades to comply with § 3179.202 until the BLM has had an opportunity to review its requirements and revise them through notice-and-comment rulemaking. The BLM is therefore proposing to delay the compliance date stated in § 3179.202 until January 17, 2019.

This proposed rule would revise paragraph (h) by replacing "no later than 1 year after the effective date of this section" in the first sentence with "by January 17, 2019" and would also replace "the effective date of this section" with "January 17, 2017" the two times that it appears later in the same sentence. This proposed rule would not otherwise revise paragraph (h); the rest of the paragraph would remain the same as in the

2016 final rule and is repeated in the proposed rule text only for context.

43 CFR 3179.203 - Storage vessels.

Section 3179.203 applies to crude oil, condensate, intermediate hydrocarbon liquid, or produced-water storage vessels that contain production from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease, and that are not subject to 40 CFR part 60, subparts OOOO or OOOOa, but would be if they were new, modified, or reconstructed sources. If such storage vessels have the potential for volatile organic compound (VOC) emissions equal to or greater than 6 tons per year (tpy), § 3179.203 requires operators to route all gas vapor from the vessels to a sales line. Alternatively, the operator may route the vapor to a combustion device if it determines that routing the vapor to a sales line is technically infeasible or unduly costly. The operator also may submit a Sundry Notice to the BLM that demonstrates that compliance with the above options would cause the operator to cease production and abandon significant recoverable oil reserves under the lease due to the cost of compliance. Pursuant to § 3179.203(c), operators must meet these requirements for covered storage vessels by January 17, 2018 (unless the operator will replace the storage vessel in order to comply, in which case it has a longer time to comply).

In the RIA for the 2016 final rule, the BLM estimated that this requirement would impose costs of about $7 million to $8 million per year and generate cost savings from product recovery of up to $200,000 per year (2016 RIA at 74).

The BLM is currently reviewing § 3179.203 to determine whether it should be rescinded or revised. The BLM is considering whether § 3179.203 is necessary in light of analogous EPA regulations and whether the costs associated with compliance are

justified. The BLM does not believe that operators should be required to make upgrades to their storage vessels in order to comply with § 3179.203 until the BLM has had an opportunity to review its requirements and revise them through notice-and-comment rulemaking. The BLM is therefore proposing to delay the January 17, 2018, compliance date in § 3179.203 until January 17, 2019.

This proposed rule would revise the first sentence of paragraph (b) by replacing "Within 60 days after the effective date of this section" with "Beginning January 17, 2019" and by adding "after January 17, 201" between the words "vessel" and "the operator." This proposed rule would also revise the introductory text of paragraph (c) by replacing "no later than one year after the effective date of this section" with "by January 17, 2019" and by changing "or three years if" to "or by January 17, 2020, if " to account for removing the reference to "the effective date of this section." This proposed rule would not otherwise revise paragraphs (b) and (c), and the rest of these paragraphs would remain the same as in the 2016 final rule and are repeated in the proposed rule text only for context.

43 CFR 3179.204 - Downhole well maintenance and liquids unloading.

Section 3179.204 establishes requirements for venting and flaring during downhole well maintenance and liquids unloading. It requires the operator to use practices for such operations that minimize vented gas and the need for well venting, unless the practices are necessary for safety. Section 3179.204 also requires that for wells equipped with a plunger lift system or an automated well-control system, the operator must optimize the operation of the system to minimize gas losses. Under § 3179.204, before an operator manually purges a well for the first time, the operator must document

in a Sundry Notice that other methods for liquids unloading are technically infeasible or unduly costly. In addition, during any liquids unloading by manual well purging, the person conducting the well purging is required to be present on-site to minimize to the maximum extent practicable any venting to the atmosphere. This section also requires the operator to maintain records of the cause, date, time, duration and estimated volume of each venting event associated with manual well purging, and to make those records available to the BLM upon request. Additionally, operators are required to notify the BLM by Sundry Notice within 30 days after the following conditions are met: (1) The cumulative duration of manual well-purging events for a well exceeds 24 hours during any production month; or (2) The estimated volume of gas vented in the process of conducting liquids unloading by manual well purging for a well exceeds 75 Mcf during any production month. In the RIA for the 2016 final rule, the BLM estimated that these requirements would impose costs of about $6 million per year and generate cost savings from product recovery of about $5 million to $9 million per year (2016 RIA at 66). In addition, there would be estimated administrative burdens associated with these requirements of $323,000 per year for the industry and $37,000 per year for the BLM (2016 RIA at 98 and 101).

The BLM is currently reviewing § 3179.204 to determine whether it should be rescinded or revised. The BLM does not believe that operators should be burdened with the operational and reporting requirements imposed by § 3179.204 until the BLM has had an opportunity to review them and, if appropriate, revise them through notice-and-comment rulemaking. In addition, as part of this review, the BLM would want to review how these data could be reported in a consistent manner among operators. The BLM is

therefore proposing to suspend the effectiveness of § 3179.204 until January 17, 2019.

This proposed rule would add a new paragraph (i), making it clear that operators must comply with § 3179.204 beginning January 17, 2019.

43 CFR 3179.301 - Operator responsibility.

Sections 3179.301 through 3179.305 establish leak detection, repair, and reporting requirements for: (1) Sites and equipment used to produce, process, treat, store, or measure natural gas from or allocable to a Federal or Indian lease, unit, or communitization agreement; and (2) Sites and equipment used to store, measure, or dispose of produced water on a Federal or Indian lease. Section 3179.302 prescribes the instruments and methods that may be used for leak detection. Section 3179.303 prescribes the frequency for inspections and § 3179.304 prescribes the time frames for repairing leaks found during inspections. Finally, § 3179.305 requires operators to maintain records of their leak detection and repair activities and submit an annual report to the BLM. Pursuant to § 3179.301(f), operators must begin to comply with the leak detection and repair requirements of §§ 3179.301 through 3179.305 before: (1) January 17, 2018, for sites in production prior to January 17, 2017; (2) 60 days after beginning production for sites that began production after January 17, 2017; and (3) 60 days after a site that was out of service is brought back into service and re-pressurized.

In the RIA for the 2016 final rule, the BLM estimated that these requirements would impose costs of about $83 million to $84 million per year and generate cost savings from product recovery of about $12 million to $21 million per year (2016 RIA at 91). In addition, there would be estimated administrative burdens associated with these

requirements of $3.9 million per year for the industry and over $1 million per year for the BLM (2016 RIA at 98 and 102).

The BLM is currently reviewing § 3179.301 through § 3179.305 to determine whether they should be revised or rescinded. The BLM is considering whether these requirements are necessary in light of comparable EPA and State leak detection and repair regulations. The BLM is considering whether the reporting burdens imposed by these sections are justified and whether the substantial compliance costs could be mitigated by allowing for less frequent and/or non-instrument-based inspections or by exempting wells that have low potential to leak natural gas. The BLM does not believe that operators should be burdened with the significant compliance costs imposed by these sections until the BLM has had an opportunity to review them and, if appropriate, revise them through notice-and-comment rulemaking. The BLM is therefore proposing to delay the effective dates for these sections until January 17, 2019, by revising § 3179.301(f).

This proposed rule would revise paragraph (f)(1) by replacing "Within one year of January 17, 2017 for sites that have begun production prior to January 17, 2017;" with "By January 17, 2019, for all existing sites." This proposed rule would also revise paragraph (f)(2) by adding "new" between the words "for" and "sites" and by replacing the existing date with "January 17, 2019." Finally, this proposed rule would revise paragraph (f)(3) by adding "an existing" between the words "when" and "site" and by adding "after January 17, 2019" to the end of the sentence. This proposed rule would not otherwise revise paragraph (f), and the rest of the paragraph would remain the same as in the 2016 final rule and is repeated in the proposed rule text only for context.

C. Summary of Estimated Impacts

The BLM reviewed the proposed rule and conducted an RIA and Environmental Assessment (EA) that examine the impacts of the proposed requirements. The following discussion is a summary of the proposed rule's economic impacts. The RIA and draft EA that we prepared have been posted in the docket for the proposed rule on the *Federal eRulemaking Portal*: https://www.regulations.gov. In the Searchbox, enter "RIN 1004-AE54" and click the "Search" button. Follow the instructions at this website.

The suspension or delay in the implementation of certain requirements in the 2016 final rule would postpone the impacts estimated previously to the near-term future. That is to say, impacts that we previously estimated would occur in 2017 are now estimated to occur in 2018, impacts that we previously estimated would occur in 2018 are now estimated to occur in 2019, and so on. In the RIA for this proposed rule, we track this shift in impacts over the 10-year period following the delay. A 10-year period of analysis was also used in the RIA prepared for the 2016 final rule. Except for some notable changes, the 2017 RIA uses the impacts estimated and underlying assumptions used by the BLM for the RIA prepared for the 2016 final rule, published in November 2016. The BLM's proposed rule would temporarily suspend or delay almost all of the requirements in the 2016 final rule that we estimated would pose a compliance burden to operators and generate benefits of gas savings or reductions in methane emissions.

<u>Estimated Reductions in Compliance Costs (Excluding Cost Savings)</u>

First, we examine the reductions in compliance costs excluding the savings that would have been realized from product recovery. The BLM's proposed rule would temporarily suspend or delay almost all of the requirements in the 2016 final rule that we estimated would pose a compliance burden to operators. We estimate that suspending or

delaying the targeted requirements of the 2016 final rule until January 17, 2019, would substantially reduce compliance costs during the period of the suspension or delay (2017 RIA at 29).

Impacts in year 1:

- A reduction in compliance costs of $114 million (using a 7 percent discount rate to annualize capital costs) or $110 million (using a 3 percent discount rate to annualize capital costs).

Impacts from 2017-2027:

- Total reduction in compliance costs ranging from $73 million to $91 million (net present value (NPV) using a 7 percent discount rate) or $40 million to $50 million (NPV using a 3 percent discount rate).

<u>Estimated Reduction in Benefits</u>

The BLM's proposed rule would temporarily suspend or delay almost all of the requirements in the 2016 final rule that we estimated would generate benefits of gas savings or reductions in methane emissions. We estimate that the proposed rule would result in forgone benefits, since estimated cost savings that would have come from product recovery would be deferred and the emissions reductions would also be deferred (2017 RIA at 32).

Impacts in year 1:

- A reduction in cost savings of $19 million.

Impacts from 2017-2027:

- Total reduction in cost savings of $36 million (NPV using a 7 percent discount rate) or $21 million (NPV using a 3 percent discount rate).

We estimate that the proposed rule would also result in additional methane and VOC emissions of 175,000 and 250,000 tons, respectively, in year 1 (2017 RIA at 32).

These estimated emissions are measured as the change from the baseline environment, which is the 2016 final rule's requirements being implemented per the 2016 final rule schedule. Since the proposed rule would delay the implementation of those requirements, the estimated benefits of the 2016 final rule would be forgone during the temporary suspension or delay.

The BLM used interim domestic values of the carbon dioxide and methane to value the forgone emissions reductions resulting from the delay (see the discussion of social cost of greenhouse gases in the 2017 RIA at Section 3.2 and Appendix).

Impact in Year 1:

- Forgone methane emissions reductions valued at $8 million (using interim domestic SC-CH_4 based on a 7 percent discount rate) or $26 million (using interim domestic SC-CH_4 based on a 3 percent discount rate).

Impacts from 2017-2027:

- Forgone methane emissions reductions valued at $1.9 million (NPV and interim domestic SC-CH_4 using a 7 percent discount rate); or
- Forgone methane emissions reductions valued at $300,000 (NPV and interim domestic SC-CH_4 using a 3 percent discount rate).

Estimated Net Benefits

The proposed rule is estimated to result in positive net benefits, meaning that the reduction of compliance costs would exceed the reduction in cost savings and the cost of emissions additions (2017 RIA at 36).

Impact in year 1:

- Net benefits of \$83 – 86 million (using interim domestic SC-CH_4 based on a 7 percent discount rate) or \$64 – 68 million (using interim domestic SC-CH_4 based on a 3 percent discount rate).

Impacts from 2017-2027:

- Total net benefits ranging from \$35 – 52 million (NPV and interim domestic SC-CH_4 using a 7 percent discount rate); or
- Total net benefits ranging from \$19 – 29 million (NPV and interim domestic SC-CH_4 using a 3 percent discount rate).

<u>Energy Systems</u>

The proposed rule is expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases, particularly in the short-term. However, since the relative changes in production are expected to be small, we do not expect that the proposed rule would significantly impact the price, supply, or distribution of energy.

We estimate the following incremental changes in production, noting the representative share of the total U.S. production in 2015 for context (2017 RIA at 41).

Annual Impacts:

- A decrease in natural gas production of 9.0 billion cubic feet (Bcf) in year 1 (0.03 percent of the total U.S. production).
- An increase in crude oil production of 91,000 barrels in year 2 (0.003 percent of the total U.S. production). There is no estimated change in crude oil production in year 1.

Royalty Impacts

In the short-term, the rule is expected to decrease natural gas production from Federal and Indian leases, and likewise, is expected to reduce annual royalties to the Federal Government, tribal governments, States, and private landowners. From 2017-2027, however, we expect a small increase in total royalties, likely due to production slightly shifting into the future where commodity prices are expected to be higher.

Royalty payments are recurring income to Federal or tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important but sometimes difficult problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.

We estimate a reduction in royalties of $2.6 million in year 1 (2017 RIA at 43). This amount represents about 0.2 percent of the total royalties received from oil and gas production on Federal lands in FY 2016. However, from 2017-2027, we estimate an increase in total royalties of $1.26 million (NPV using a 7 percent discount rate) or $380,000 (NPV using a 3 percent discount rate).

Consideration of Alternative Approaches

In developing this proposed rule, the BLM considered alternative timeframes for which it could suspend or delay the requirements (e.g., 6 months and 2 years). Ultimately, the BLM decided to propose a suspension or delay for one year, which it believes to be the minimum length of time practicable within which to review the 2016 final rule and complete a notice-and-comment rulemaking to revise that regulation. We

note that, based on the progress of the review during this rulemaking process, the BLM may revise the length of the suspension or delay for the final rule.

A shorter suspension of delay of the same 2016 final rule requirements would result in a smaller reduction in compliance costs, smaller reduction in cost savings, and a smaller amount of forgone emissions reductions, relative to the proposal (2017 RIA at 49-50). Meanwhile, a longer suspension or delay of the same 2016 final rule requirements would result in a larger reduction in compliance costs, larger reduction in cost savings, and larger amount of forgone emissions reductions, relative to the proposal (2017 RIA at 50).

<u>Employment Impacts</u>

The proposed rule would temporarily suspend or delay certain requirements of the BLM's 2016 final rule on waste prevention and is a temporary deregulatory action. As such, we estimate that it would result in a reduction of compliance costs for operators of oil and gas leases on Federal and Indian lands. Therefore, it is likely that the impact, if any, on the employment would be positive.

In the RIA for the 2016 final rule, the BLM concluded that the requirements were not expected to impact the employment within the oil and gas extraction, drilling oil and gas wells, and support activities industries, in any material way. This determination was based on several reasons. First, the estimated incremental gas production represented only a small fraction of the U.S. natural gas production volumes. Second, the estimated compliance costs represented only a small fraction of the annual net incomes of companies likely to be impacted. Third, for those operations that would have been impacted to the extent that the compliance costs would force the operator to shut in

production, the 2016 final rule had provisions that would exempt these operations from compliance. Based on these factors, the BLM determined that the 2016 final rule would not alter the investment or employment decisions of firms or significantly adversely impact employment. The RIA also noted that the requirements would require the one-time installation or replacement of equipment and the ongoing implementation of a leak detection and repair program, both of which would require labor to comply.

We do not believe that the proposed rule would substantially alter the investment or employment decisions of firms for two reasons. First, the RIA for the 2016 final rule determined that that rule would not substantially alter the investment or employment decisions of firms, and so therefore delaying the 2016 final rule would likewise not be expected to impact those decisions. We also recognize that while there might be a small positive impact on investment and employment due to the reduction in compliance burdens, the magnitude of the reductions are relatively small.

<u>Small Business Impacts</u>

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau. We conclude that small entities represent the overwhelming majority of entities operating in the onshore crude oil and natural gas extraction industry and, therefore, the proposed rule would impact a significant number of small entities.

To examine the economic impact of the rule on small entities, the BLM performed a screening analysis on a sample of potentially affected small entities, comparing the reduction of compliance costs to entity profit margins.

The BLM identified up to 1,828 entities that operate on Federal and Indian leases and recognizes that the overwhelming majority of these entities are small business, as defined by the SBA. We estimated the potential reduction in compliance costs to be about $60,000 per entity during the initial year when the requirements would be suspended or delayed. This represents the average maximum amount by which the operators would be positively impacted by the proposed rule.

We used existing BLM information and research concerning firms that have recently completed Federal and Indian wells and the financial and employment information on a sample of these firms, as available in company annual report filings with the Securities and Exchange Commission (SEC). From the original list of companies, we identified 55 company filings. Of those companies, 33 were small businesses.

From data in the companies' 10-K filings to the SEC, the BLM was able to calculate the companies' profit margins for the years 2012, 2013, and 2014. We then calculated a profit margin figure for each company when subject to the average annual reduction in compliance costs associated with this proposed rule. For these 26 small companies, the estimated per-entity reduction in compliance costs would result in an average increase in profit margin of 0.17 percentage points (based on the 2014 company data) (2017 RIA at 46).

<u>Impacts Associated with Oil and Gas Operations on Tribal Lands</u>

The proposed rule would apply to oil and gas operations on both Federal and Indian leases. In the RIA, the BLM estimates the impacts associated with operations on Indian leases, as well as royalty implications for tribal governments. We estimate these

impacts by scaling down the total impacts by the share of oil wells on Indian lands and the share of gas wells on Indian Lands. Please reference the RIA at section 4.4.5 for a full explanation about the estimate impacts.

IV. Procedural Matters

Regulatory Planning and Review (Executive Orders 12866 and 13563)

Executive Order 12866 provides that the Office of Information and Regulatory Affairs within the Office of Management and Budget (OMB) will review all significant rules.

Executive Order 13563 reaffirms the principles of Executive Order 12866 while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The Executive Order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. Executive Order 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas.

This proposed rule would temporarily suspend or delay portions of the BLM's 2016 final rule while the BLM reviews those requirements. We have developed this proposed rule in a manner consistent with the requirements in Executive Order 12866 and Executive Order 13563.

After reviewing the requirements of the proposed rule, the OMB has determined that it is an economically significant action according to the criteria of Executive Order

12866. The BLM reviewed the requirements of the proposed rule and determined that it will not adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. For more detailed information, see the RIA prepared for this proposed rule. The RIA has been posted in the docket for the proposed rule on the *Federal eRulemaking Portal*: https://www.regulations.gov. In the Searchbox, enter "RIN 1004-AE54" and click the "Search" button. Follow the instructions at this website.

Regulatory Flexibility Act

This proposed rule would not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) The Regulatory Flexibility Act (RFA) generally requires that Federal agencies prepare a regulatory flexibility analysis for rules subject to the notice-and-comment rulemaking requirements under the Administrative Procedure Act (5 U.S.C. 500 *et seq.*), if the rule would have a significant economic impact, either detrimental or beneficial, on a substantial number of small entities. *See* 5 U.S.C. 601 – 612. Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the SBA size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the

relevant sectors are small businesses as defined by the SBA. As such, the proposed rule would likely affect a substantial number of small entities.

However, the BLM believes that the proposed rule would not have a significant economic impact on a substantial number of small entities. Although the rule would affect a substantial number of small entities, the BLM does not believe that these effects would be economically significant. The proposed rule would temporarily suspend or delay certain requirements placed on operators by the 2016 final rule. Operators would not have to undertake the associated compliance activities, either operational or administrative, that are outlined in the 2016 final rule until January 17, 2019, except to the extent the activities are required by State or tribal law, or by other pre-existing BLM regulations. The screening analysis conducted by the BLM estimates that the average reduction in compliance costs associated with this proposed rule would be a small fraction of a percent of the profit margin for small companies, which is not a large enough impact to be considered significant.

Small Business Regulatory Enforcement Fairness Act

This proposed rule is a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This proposed rule:

(a) Would have an annual effect on the economy of $100 million or more.

(b) Would not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

(c) Would not have a significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

Unfunded Mandates Reform Act (UMRA)

This proposed rule would not impose an unfunded mandate on State, local, or tribal governments, or the private sector of $100 million or more per year. The proposed rule would not have a significant or unique effect on State, local, or tribal governments or the private sector. The proposed rule contains no requirements that would apply to State, local, or tribal governments. It would temporarily suspend or delay requirements that would otherwise apply to the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1531 *et seq.*) is not required for the proposed rule. This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments, because it contains no requirements that apply to such governments, nor does it impose obligations upon them.

Governmental Actions and Interference with Constitutionally Protected Property Right - Takings (Executive Order 12630)

This proposed rule would not affect a taking of private property or otherwise have taking implications under Executive Order 12630. A takings implication assessment is not required. The proposed rule would temporarily suspend or delay many of the requirements placed on operators by the 2016 final rule. Operators would not have to undertake the associated compliance activities, either operational or administrative, that are outlined in the 2016 final rule until January 17, 2019, and therefore would impact some operational and administrative requirements on Federal and Indian lands. All such operations are subject to lease terms which expressly require that subsequent lease activities be conducted in compliance with subsequently adopted Federal laws and

regulations. This proposed rule conforms to the terms of those leases and applicable statutes and, as such, the rule is not a government action capable of interfering with constitutionally protected property rights. Therefore, the BLM has determined that the rule would not cause a taking of private property or require further discussion of takings implications under Executive Order 12630.

Federalism (Executive Order 13132)

Under the criteria in section 1 of Executive Order 13132, this proposed rule does not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement. A federalism impact statement is not required.

The proposed rule would not have a substantial direct effect on the States, on the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the levels of government. It would not apply to States or local governments or State or local governmental entities. The rule would affect the relationship between operators, lessees, and the BLM, but it does not directly impact the States. Therefore, in accordance with Executive Order 13132, the BLM has determined that this proposed rule does not have sufficient federalism implications to warrant preparation of a Federalism Assessment.

Civil Justice Reform (Executive Order 12988)

This proposed rule complies with the requirements of Executive Order 12988. More specifically, this proposed rule meets the criteria of section 3(a), which requires agencies to review all regulations to eliminate errors and ambiguity and to write all regulations to minimize litigation. This proposed rule also meets the criteria of section

3(b)(2), which requires agencies to write all regulations in clear language with clear legal standards.

Consultation and Coordination with Indian Tribal Governments (Executive Order 13175 and Departmental Policy)

The Department strives to strengthen its government-to-government relationship with Indian tribes through a commitment to consultation with Indian tribes and recognition of their right to self-governance and tribal sovereignty. We have evaluated this proposed rule under the Department's consultation policy and under the criteria in Executive Order 13175 and have identified substantial direct effects on federally recognized Indian tribes that would result from this proposed rule. Under this proposed rule, oil and gas operations on tribal and allotted lands would not be subject to many of the requirements placed on operators by the 2016 final rule until January 17, 2019.

The BLM believes that temporarily suspending or delaying these requirements would assist in preventing Indian lands from being viewed by oil and gas operators as less attractive than non-Indian lands due to unnecessary and burdensome compliance costs, thereby preventing economic harm to tribes and allottees.

The BLM is conducting tribal outreach which it believes is appropriate given that the proposed rule would extend the compliance dates of the 2016 final rule, but would not change the policies of that rule. The BLM notified tribes of the action and requested feedback and comment through the respective BLM State Office Directors. Future tribal consultation may occur on an ongoing basis.

Paperwork Reduction Act

1. Overview

The Paperwork Reduction Act (PRA) (44 U.S.C. 3501–3521) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid control number. 44 U.S.C. 3512. Collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency. 44 U.S.C. 3502(3); 5 CFR 1320.3(c) and (k).

OMB has approved the 24 information collection activities in the 2016 final rule and has assigned control number 1004-0211 to those activities. In the Notice of Action approving the 24 information collection activities in the 2016 final rule, OMB announced that the control number will expire on January 31, 2018. The Notice of Action also included terms of clearance.

The BLM requests the extension of control number 1004-0021 until January 31, 2019. The BLM requests no other changes to the control number.

In accordance with the PRA, the BLM is inviting public comment on the proposed extension of control no. 1004-0211. Descriptions of the information collection activities in this proposed rule, along with estimates of the annual burdens, are shown below. Included in the burden estimates are the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing each component of the proposed information collection requirements.

The BLM has submitted the information collection request for this proposed rule to OMB for review in accordance with the PRA. You may obtain a copy of the request from the BLM by electronic mail request to James Tichenor at jtichenor@blm.gov or by

telephone request to 202–573–0536. You may also review the information collection request online at: http://www.reginfo.gov/public/do/ .

The BLM requests comments on the following subjects:

- Whether the collection of information is necessary for the proper functioning of the BLM, including whether the information will have practical utility;
- The accuracy of the BLM's estimate of the burden of collecting the information, including the validity of the methodology and assumptions used;
- The quality, utility, and clarity of the information to be collected; and
- How to minimize the information collection burden on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other forms of information technology.

If you want to comment on the information collection requirements of this proposed rule, please send your comments directly to OMB, with a copy to the BLM, as directed in the ADDRESSES section of this preamble. Please identify your comments with ''OMB Control Number 1004–0211.'' OMB is required to make a decision concerning the collection of information contained in this proposed rule between 30 to 60 days after publication of this document in the Federal Register. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

2. Summary of Information Collection Activities

Title: Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR parts 3160 and 3170).Form 3160–5, Sundry Notices and Reports on Wells.

OMB Control Number: 1004–0211.

Forms: Form 3160-3, Application for Permit to Drill or Re-enter; and

Form 3160–5, Sundry Notices and Reports on Wells.

Description of Respondents: Holders of Federal and Indian (except Osage Tribe) oil and gas leases, those who belong to Federally approved units or communitized areas, and those who are parties to oil and gas agreements under the Indian Mineral Development Act, 25 U.S.C. 2101–2108.

Respondents' Obligation: Required to obtain or retain a benefit.

Frequency of Collection: On occasion.

Abstract: The BLM requests the extension of control number 1004-0021 until January 31, 2019. The BLM requests no changes to the control number except this extension.

Estimated Number of Responses: 63,200.

Estimated Total Annual Burden Hours: 82,170.

Estimated Total Non-Hour Cost: None.

3. Information Collection Request

The BLM requests extension of OMB control number 1004-0211 until January 31, 2019. This extension would continue OMB's approval of the following information collection activities.

Plan to Minimize Waste of Natural Gas (43 CFR 3162.3-1)

The 2016 final rule added a new provision to 43 CFR 3162.3-1 that requires a plan to minimize waste of natural gas when submitting an Application for Permit to Drill or Re-enter (APD) for a development oil well. This information is in addition to the APD information that the BLM already collects under OMB Control Number 1004-0137. The

required elements of the waste minimization plan are listed at paragraphs (j)(1) through (j)(7).

Request for Approval for Royalty-Free Uses On-Lease or Off-Lease (43 CFR 3178.5, 3178.7, 3178.8, and 3178.9)

Section 3178.5 requires submission of a Sundry Notice (Form 3160-5) to request prior written BLM approval for use of gas royalty-free for the following operations and production purposes on the lease, unit or communitized area:

- Using oil or gas that an operator removes from the pipeline at a location downstream of the facility measurement point (FMP);
- Removal of gas initially from a lease, unit PA, or communitized area for treatment or processing because of particular physical characteristics of the gas, prior to use on the lease, unit PA or communitized area; and
- Any other type of use of produced oil or gas for operations and production purposes pursuant to § 3178.3 that is not identified in § 3178.4.

Section 3178.7 requires submission of a Sundry Notice (Form 3160-5) to request prior written BLM approval for off-lease royalty-free uses in the following circumstances:

- The equipment or facility in which the operation is conducted is located off the lease, unit, or communitized area for engineering, economic, resource-protection, or physical-accessibility reasons; and
- The operations are conducted upstream of the FMP.

Section 3178.8 requires that an operator measure or estimate the volume of royalty-free gas used in operations upstream of the FMP. In general, the operator is free

to choose whether to measure or estimate, with the exception that the operator must in all cases measure the following volumes:

- Royalty-free gas removed downstream of the FMP and used pursuant to §§ 3178.4 through 3178.7; and
- Royalty-free oil used pursuant to §§ 3178.4 through 3178.7.

If oil is used on the lease, unit or communitized area, it is most likely to be removed from a storage tank on the lease, unit or communitized area. Thus, this regulation also requires the operator to document the removal of the oil from the tank or pipeline.

Section 3178,8(e) requires that operators use best available information to estimate gas volumes, where estimation is allowed. For both oil and gas, the operator must report the volumes measured or estimated, as applicable, under ONRR reporting requirements. As revisions to Onshore Oil and Gas Orders No. 4 and 5 have now been finalized as 43 CFR subparts 3174 and 3175, respectively, the final rule text now references § 3173.12, as well as §3178.4 through §3178.7 to clarify that royalty-free use must adhere to the provisions in those sections.

Section 3178.9 requires the following additional information in a request for prior approval of royalty-free use under § 3178.5, or for prior approval of off-lease royalty-free use under § 3178.7:

- A complete description of the operation to be conducted, including the location of all facilities and equipment involved in the operation and the location of the FMP;
- The volume of oil or gas that the operator expects will be used in the operation and the method of measuring or estimating that volume;

- If the volume expected to be used will be estimated, the basis for the estimate (e.g., equipment manufacturer's published consumption or usage rates); and
- The proposed disposition of the oil or gas used (e.g., whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or disposed by some other method).

Request for Approval of Alternative Capture Requirement (43 CFR 3179.8)

Section 3179.8 applies only to leases issued before the effective date of the 2016 final rule and to operators choosing to comply with the capture requirement in § 3179.7 on a lease-by-lease, unit-by-unit, or communitized area-by-communitized area basis. The regulation provides that operators who meet those parameters may seek BLM approval of a capture percentage other than that which is applicable under 43 CFR 3179.7. The operator must submit a Sundry Notice (Form 3160-5) that includes the following information:

- The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated; and
- The oil and gas production levels of each of the operator's wells on the lease, unit, or communitized area for the most recent production month for which information is available and the volumes being vented and flared from each well.

In addition, the request must include map(s) showing:

- The entire lease, unit, or communitized area, and the surrounding lands to a distance and on a scale that shows the field in which the well is or will be located (if applicable), and all pipelines that could transport the gas from the well;

- All of the operator's producing oil and gas wells, which are producing from Federal or Indian leases, (both on Federal or Indian leases and on other properties) within the map area;
- Identification of all of the operator's wells within the lease from which gas is flared or vented, and the location and distance of the nearest gas pipeline(s) to each such well, with an identification of those pipelines that are or could be available for connection and use; and
- Identification of all of the operator's wells within the lease from which gas is captured;

The following information is also required:

- Data that show pipeline capacity and the operator's projections of the cost associated with installation and operation of gas capture infrastructure, to the extent that the operator is able to obtain this information, as well as cost projections for alternative methods of transportation that do not require pipelines; and
- Projected costs of and the combined stream of revenues from both gas and oil production, including: (1) The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H_2S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and (2) The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas

operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

Notification of Choice to Comply on County- or State-wide Basis (43 CFR 3179.7(c)(3)(ii))

Section 3179.7 requires operators flaring gas from development oil wells to capture a specified percentage of the operator's adjusted volume of gas produced over the relevant area. The "relevant area" is each of the operator's leases, units, or communitized areas, unless the operator chooses to comply on a county- or State-wide basis and the operator notifies the BLM of its choice by Sundry Notice (Form 3160-5) by January 1 of the relevant year.

Request for Exemption from Well Completion Requirements (43 CFR 3179.102(c) and (d))

Section 3179.102 lists several requirements pertaining to gas that reaches the surface during well completion and related operations. An operator may seek an exemption from these requirements by submitting a Sundry Notice (Form 3160-5) that includes the following information:

(1) The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance; and

(4) Projected costs of and the combined stream of revenues from both gas and oil production, including: the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H_2S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

The rule also provides that an operator that is in compliance with the EPA regulations for well completions under 40 CFR part 60, subpart OOOO or subpart OOOOa is deemed in compliance with the requirements of this section. As a practical matter, all new, reconstructed, and modified hydraulically fracturing or refracturing events are now subject to the EPA requirements, so the BLM does not believe that the requirements of this section would have any independent effect, or that any operator would request an exemption from the requirements of this section, as long as the EPA requirements remain in effect. For this reason, the BLM is not estimating any PRA burdens for § 3179.102.[4]

Request for Extension of Royalty-Free Flaring During Initial Production Testing (43 CFR 3179.103)

Section 3179.103 allows gas to be flared royalty-free during initial production testing. The regulation lists specific volume and time limits for such testing. An operator may seek an extension of those limits on royalty-free flaring by submitting a Sundry Notice (Form 3160-5) to the BLM.

[4] The EPA has convened a proceeding for reconsidering the final OOOOa rule, see 82 FR 25730 (June 5, 2017). If EPA's requirements are altered in any way in the future, then PRA burdens estimated for BLM's rule could increase by up to $130/event if the operator files for an exemption.

Request for Extension of Royalty-Free Flaring During Subsequent Well Testing (43 CFR 3179.104)

Section 3179.104 allows gas to be flared royalty-free for no more than 24 hours during well tests subsequent to the initial production test. The operator may seek authorization to flare royalty-free for a longer period by submitting a Sundry Notice (Form 3160-5) to the BLM.

Reporting of Venting or Flaring (43 CFR 3179.105)

Section 3179.105 allows an operator to flare gas royalty-free during a temporary, short-term, infrequent, and unavoidable emergency. Venting gas is permissible if flaring is not feasible during an emergency. The regulation defines limited circumstances that constitute an emergency, and other circumstances that do not constitute an emergency.

The operator must estimate and report to the BLM on a Sundry Notice (Form 3160-5) volumes flared or vented in circumstances that, as provided by 43 CFR 3179.105, do not constitute emergencies for the purposes of royalty assessment:

(1) More than 3 failures of the same component within a single piece of equipment within any 365-day period;

(2) The operator's failure to install appropriate equipment of a sufficient capacity to accommodate the production conditions;

(3) Failure to limit production when the production rate exceeds the capacity of the related equipment, pipeline, or gas plant, or exceeds sales contract volumes of oil or gas;

(4) Scheduled maintenance;

(5) A situation caused by operator negligence; or

(6) A situation on a lease, unit, or communitized area that has already experienced 3 or more emergencies within the past 30 days, unless the BLM determines that the occurrence of more than 3 emergencies within the 30 day period could not have been anticipated and was beyond the operator's control.

Pneumatic Controllers — Introduction

Section 3179.201 pertains to any pneumatic controller that: (1) is not subject to EPA regulations at 40 CFR 60.5360a through 60.5390a, but would be subject to those regulations if it were a new or modified source; and (2) has a continuous bleed rate greater than 6 standard cubic feet (scf) per hour. Section 3179.201(b) requires operators to replace each high-bleed pneumatic controller with a controller with a bleed rate lower than 6 scf per hour, with the following exceptions: (1) the pneumatic controller exhaust is routed to processing equipment; (2) the pneumatic controller exhaust was and continues to be routed to a flare device or low pressure combustor; (3) The pneumatic controller exhaust is routed to processing equipment; or (4) The operator notifies the BLM through a Sundry Notice and demonstrates, and the BLM agrees, that such would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

Notification of Functional Needs for a Pneumatic Controller (43 CFR 3179.201(b)(1) – (3))

An operator may invoke one of the first three exceptions described above by notifying the BLM through a Sundry Notice (Form 3160-5) that use of the pneumatic controller is required based on functional needs that may include, but are not limited to,

response time, safety, and positive actuation, and the Sundry Notice (Form 3160-5) describes those functional needs.

Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (43 CFR 3175.201(b)(4) and 3175.201(c))

An operator may invoke the fourth exception described above by demonstrating to the BLM through a Sundry Notice (Form 3160-5), and by obtaining the BLM's agreement, that replacement of a pneumatic controller would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. The Sundry Notice (Form 3160-5) must include the following information:

(1) The name, number, and location of each of the operator's wells, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance;

(4) Projected costs of and the combined stream of revenues from both gas and oil production, including: the operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H_2S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and the operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments

from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

Showing in Support of Replacement of Pneumatic Controller within 3 Years (43 CFR 3179.201(d))

The operator may replace a high-bleed pneumatic controller if the operator notifies the BLM through a Sundry Notice (Form 3160-5) that the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less.

Pneumatic Diaphragm Pumps — Introduction

With some exceptions, § 3179.202 pertains to any pneumatic diaphragm pump that: (1) Uses natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease; and (2) Is not subject to EPA regulations at 40 CFR 60.5360a through 60.5390a, but would be subject to those regulations if it were a new, reconstructed, or modified source as defined in 40 CFR part 60 subpart OOOOa. This regulation generally requires replacement of such a pump with a zero-emissions pump or routing of the pump's exhaust gas to processing equipment for capture and sale.

This requirement does not apply to pneumatic diaphragm pumps that do not vent exhaust gas to the atmosphere. In addition, this requirement does not apply if the operator submits a Sundry Notice to the BLM documenting that the pump(s) operated on less than 90 individual days in the prior calendar year.

Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year (43 CFR 3179.202(b)(2))

A pneumatic diaphragm pump is not subject to § 3179.202 if the operator documents in a Sundry Notice (Form 3160-5) that the pump was operated fewer than 90 days in the prior calendar year.

Notification of Functional Needs for a Pneumatic Diaphragm Pump (43 CFR 3179.202(d))

In lieu of replacing a pneumatic diaphragm pump or routing the pump exhaust gas to processing equipment, an operator may submit a Sundry Notice (Form 3160-5) to the BLM showing that replacing the pump with a zero emissions pump is not viable because a pneumatic pump is necessary to perform the function required, and that routing the pump exhaust gas to processing equipment for capture and sale is technically infeasible or unduly costly.

Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (43 CFR 3175.202(f) and (g))

An operator may seek an exemption from the replacement requirement by submitting a Sundry Notice (Form 3160-5) to the BLM that provides an economic analysis that demonstrates that compliance with these requirements would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease. The Sundry Notice (Form 3160-5) must include the following information:

(1) Well information that must include: (i) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated; and (ii) The oil and gas production levels of each of the operator’s wells on the lease, unit or

communitized area for the most recent production month for which information is available;

(2) Data that show the costs of compliance with § 3179.202(c) through (e); and

(3) The operator's estimate of the costs and revenues of the combined stream of revenues from both the gas and oil components, including: (i) The operator's projections of gas prices, gas production volumes, gas quality (i.e., heating value and H_2S content), revenues derived from gas production, and royalty payments on gas production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less; and (ii) The operator's projections of oil prices, oil production volumes, costs, revenues, and royalty payments from the operator's oil and gas operations within the lease over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years (43 CFR 3179.202(h))

The operator may replace a pneumatic diaphragm pump if the operator notifies the BLM through a Sundry Notice (Form 3160-5) that the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less.

Storage Vessels (43 CFR 3179.203(c) and (d)).

A storage vessel is subject to 43 CFR 3179.203(c) if the vessel: (1) contains production from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease; and (2) Is not subject to any of the requirements of EPA regulations at 40 CFR part 60, subpart OOOO, but would be subject to that subpart if it were a new, reconstructed, or modified source.

The operator must determine, record, and make available to the BLM upon request, whether the storage vessel has the potential for VOC emissions equal to or greater than 6 tpy based on the maximum average daily throughput for a 30-day period of production. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority that limit the VOC emissions to less than 6 tpy.

If a storage vessel has the potential for VOC emissions equal to or greater than 6 tpy, the operator must replace the storage vessel at issue in order to comply with the requirements of this section, and the operator must

(1) Route all tank vapor gas from the storage vessel to a sales line;

(2) If the operator determines that compliance with the requirement to route all tank vapor gas from the storage vessel to a sales line is technically infeasible or unduly costly, route all tank vapor gas from the storage vessel to a device or method that ensures continuous combustion of the tank vapor gas; or

(3) Submit an economic analysis to the BLM through a Sundry Notice (Form 3160-5) that demonstrates, and the BLM agrees, that compliance with § 3179.203(c)(2) would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

To support the demonstration described above, the operator must submit a Sundry Notice (Form 3160-5) that includes the following information:

(1) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance with § 3179.203(c)(1) or (2) on the lease; and

(4) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components, including: the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H_2S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less.

Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting (43 CFR 3179.204(c) and (e))

The operator must minimize vented gas and the need for well venting associated with downhole well maintenance and liquids unloading, consistent with safe operations. Before the operator manually purges a well for liquids unloading for the first time after the effective date of this section, the operator must consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly. The operator must provide information supporting that determination as part of a Sundry Notice (Form 3160-5). This requirement applies to each well the operator operates.

For any liquids unloading by manual well purging, the operator must:

1) Ensure that the person conducting the well purging remains present on-site throughout the event to minimize to the maximum extent practicable any venting to the atmosphere;

(2) Record the cause, date, time, duration, and estimated volume of each venting event; and

(3) Maintain the records for the period required under § 3162.4-1 and make them available to the BLM, upon request.

Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume (43 CFR 3179.204(f))

The operator must notify the BLM by Sundry Notice (Form 3160-5), within 30 calendar days, if:

(1) The cumulative duration of manual well purging events for a well exceeds 24 hours during any production month; or

(2) The estimated volume of gas vented in liquids unloading by manual well purging operations for a well exceeds 75 Mcf during any production month.

Leak Detection — Compliance with EPA Regulations (43 CFR 3179.301(j))

Sections 3179.301 through 3179.305 include information collection activities pertaining to the detection and repair of gas leaks during production operations. These regulations require operators to inspect all equipment covered under § 3179.301(a) for gas leaks.

Section 3179.301(j) allows an operator to satisfy the requirements of §§ 3179.301 through 3179.305 for some or all of the equipment or facilities on a given lease by notifying the BLM in a Sundry Notice (Form 3160-5) that the operator is complying with EPA requirements established pursuant to 40 CFR part 60 with respect to such equipment or facilities.

Leak Detection — Request to Use an Alternative Monitoring Device and Protocol (43 CFR 3179.302(c))

Section 3175.302 specifies the instruments and methods that an operator may use to detect leaks. Section 3175.302(d) allows the BLM to approve an alternative monitoring device and associated inspection protocol if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared with the approach specified in §3179.302(a)(1) when used according to § 3179.303(a).

Any person may request approval of an alternative monitoring device and protocol by submitting a Sundry Notice (Form 3160-5) to BLM that includes the following information: (1) Specifications of the proposed monitoring device, including a detection limit capable of supporting the desired function; (2) The proposed monitoring protocol using the proposed monitoring device, including how results will be recorded; (3) Records and data from laboratory and field testing, including but not limited to performance testing; (4) A demonstration that the proposed monitoring device and protocol will achieve equal or greater reduction of gas lost through leaks compared with the approach specified in the regulations; (5) Tracking and documentation procedures; and (6) Proposed limitations on the types of sites or other conditions on deploying the device and the protocol to achieve the demonstrated results.

Leak Detection — Operator Request to Use an Alternative Leak Detection Program (43 CFR 3179.303(b))

Section 3179.303(b) allows an operator to submit a Sundry Notice (Form 3160-5) requesting authorization to detect gas leaks using an alternative instrument-based leak detection program, different from the specified requirement to inspect each site semi-annually using an approved monitoring device.

To obtain approval for an alternative leak detection program, the operator must submit a Sundry Notice (Form 3160-5) that includes the following information:

(1) A detailed description of the alternative leak detection program, including how it will use one or more of the instruments specified in or approved under § 3179.302(a) and an identification of the specific instruments, methods and/or practices that would substitute for specific elements of the approach specified in §§ 3179.302(a) and 3179.303(a);

(2) The proposed monitoring protocol;

(3) Records and data from laboratory and field testing, including, but not limited to, performance testing, to the extent relevant;

(4) A demonstration that the proposed alternative leak detection program will achieve equal or greater reduction of gas lost through leaks compared to compliance with the requirements specified in §§ 3179.302(a) and 3179.303(a);

(5) A detailed description of how the operator will track and document its procedures, leaks found, and leaks repaired; and

(6) Proposed limitations on types of sites or other conditions on deployment of the alternative leak detection program.

Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified Criteria (43 CFR 3179.303(d))

An operator may seek authorization for an alternative leak detection program that does not achieve equal or greater reduction of gas lost through leaks compared to the required approach, if the operator demonstrates that compliance with the leak-detection regulations (including the option for an alternative program under 43 CFR 3179.303(b)) would impose such costs as to cause the operator to cease production and abandon

significant recoverable oil or gas reserves under the lease. The BLM may approve an alternative leak detection program that does not achieve equal or greater reduction of gas lost through leaks, but is as effective as possible consistent with not causing the operator to cease production and abandon significant recoverable oil or gas reserves under the lease.

To obtain approval for an alternative program under this provision, the operator must submit a Sundry Notice (Form 3160-5) that includes the following information:

(1) The name, number, and location of each well, and the number of the lease, unit, or communitized area with which it is associated;

(2) The oil and gas production levels of each of the operator's wells on the lease, unit or communitized area for the most recent production month for which information is available;

(3) Data that show the costs of compliance on the lease with the requirements of §§ 3179.301-305 and with an alternative leak detection program that meets the requirements of §3179.303(b);

(4) The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and H_2S content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease, unit, or communitized area, whichever is less;

(5) The information required to obtain approval of an alternative program under §3179.303(b), except that the estimated volume of gas that will be lost through leaks

under the alternative program must be compared to the volume of gas lost under the required program, but does not have to be shown to be at least equivalent.

Leak Detection — Notification of Delay in Repairing Leaks (43 CFR 3179.304(b))

Section 3179.304(a) requires an operator to repair any leak no later than 30 calendar days after discovery of the leak, unless there is good cause for delay in repair. If there is good cause for a delay beyond 30 calendar days, § 3179.304(b) requires the operator to submit a Sundry Notice (Form 3160-5) notifying the BLM of the cause.

Leak Detection — Inspection Recordkeeping and Reporting (43 CFR 3179.305)

Section 3179.305 requires operators to maintain the following records and make them available to the BLM upon request: (1) For each inspection required under § 3179.303, documentation of the date of the inspection and the site where the inspection was conducted; (2) The monitoring method(s) used to determine the presence of leaks; (3) A list of leak components on which leaks were found; (4) The date each leak was repaired; and (5) The date and result of the follow-up inspection(s) required under § 3179.304. By March 31 each calendar year, the operator must provide to the BLM an annual summary report on the previous year's inspection activities that includes: (1) The number of sites inspected; (2) The total number of leaks identified, categorized by the type of component; (3) The total number of leaks repaired; (4) The total number of leaks that were not repaired as of December 31 of the previous calendar year due to good cause and an estimated date of repair for each leak; and (5) A certification by a responsible officer that the information in the report is true and accurate.

Leak Detection — Annual Reporting of Inspections (43 CFR 3179.305(b))

By March 31 of each calendar year, the operator must provide to the BLM an annual summary report on the previous year's inspection activities that includes:

(1) The number of sites inspected;

(2) The total number of leaks identified, categorized by the type of component;

(3) The total number of leaks repaired;

(4) The total number leaks that were not repaired as of December 31 of the previous calendar year due to good cause and an estimated date of repair for each leak.

(5) A certification by a responsible officer that the information in the report is true and accurate to the best of the officer's knowledge.

4. Burden Estimates

The following table details the annual estimated hour burdens for the information activities described above.

A. Type of Response	B. Number of Responses	C. Hours per Response	D. Total Hours (Column B x Column C)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1 Form 3160-3	2,000	8	16,000
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	4	200
Notification of Choice to Comply on County- or State-wide Basis 43 CFR 3179.7(c)(3)(iii)	200	1	200

Request for Approval of Alternative Capture Requirement 43 CFR 3179.8(b) Form 3160-5	50	16	800
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	0	0	0
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.103 Form 3160-5	500	2	1000
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.104 Form 3160-5	5	2	10
Reporting of Venting or Flaring 43 CFR 3179.105 Form 3160-5	250	2	500
Notification of Functional Needs for a Pneumatic Controller 43 CFR 3179.201(b)(1) – (3) Form 3160-5	10	2	20
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3175.201(b)(4) and 3175.201(c) Form 3160-5	50	4	200
Showing in Support of Replacement of Pneumatic Controller within 3 Years 43 CFR 3179.201(d) Form 3160-5	100	1	100

Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year 43 CFR 3179.202(b)(2) Form 3160-5	100	1	100
Notification of Functional Needs for a Pneumatic Diaphragm Pump 43 CFR 3179.202(d) Form 3160-5	150	1	150
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves 43 CFR 3175.202(f) and (g) Form 3160-5	10	4	40
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	1	100
Storage Vessels 43 CFR 3179.203(c) Form 3160-5	50	4	200
Downhole Well Maintenance and Liquids Unloading — Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	1	5,000
Downhole Well Maintenance and Liquids Unloading — Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	1	250
Leak Detection — Compliance with EPA Regulations 43 CFR 3179.301(j) Form 3160-5	50	4	200

Leak Detection — Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) Form 3160-5	5	40	200
Leak Detection — Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800
Leak Detection — Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified 43 CFR 3179.303(d) Form 3160-5	150	20	3,000
Leak Detection — Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) Form 3160-5	100	1	100
Leak Detection — Inspection Recordkeeping and Reporting 43 CFR 3179.305	52,000	.25	13,000
Leak Detection — Annual Reporting of Inspections 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000
Totals	63,200	—	82,170

National Environmental Policy Act

The BLM has prepared a draft environmental assessment (EA) to determine whether this proposed rule would have a significant impact on the quality of the human environment under the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321 *et seq.*). If the final EA supports the issuance of a Finding of No Significant Impact

(FONSI) for the rule, the preparation of an environmental impact statement pursuant to the NEPA would not be required.

The draft EA and FONSI have been placed in the file for the BLM's Administrative Record for the rule at the address specified in the "ADDRESSES" section. The EA and FONSI have also been posted in the docket for the rule on the *Federal eRulemaking Portal*: https://www.regulations.gov. In the Searchbox, enter "RIN 1004-AE54" and click the "Search" button. Follow the instructions at this website. The BLM invites the public to review these documents and suggests that anyone wishing to submit comments on the EA and FONSI should do so in accordance with the instructions contained in the "Public Comment Procedures" section above.

Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use (Executive Order 13211)

This proposed rule is not a significant energy action under the definition in Executive Order 13211. A statement of Energy Effects is not required.

Section 4(b) of Executive Order 13211 defines a "significant energy action" as "any action by an agency (normally published in the *Federal Register*) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of rulemaking, and notices of rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) Is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) That is designated by the Administrator of [OIRA] as a significant energy action."

The rule temporarily suspends or delays certain requirements in the 2016 final rule and would reduce compliance costs in the short-term. The BLM determined that the 2016 final rule would not have impacted the supply, distribution, or use of energy and so the suspension or delay of many of the 2016 final rule's requirements until January 17, 2019, will likewise not have an impact on the supply, distribution, or use of energy. As such, we do not consider the proposed rule to be a "significant energy action" as defined in Executive Order 13211.

Clarity of this Regulation (Executive Orders 12866)

We are required by Executive Orders 12866 (section 1(b)(12)), 12988 (section 3(b)(1)(B)), and 13563 (section 1(a)), and by the Presidential Memorandum of June 1, 1988, to write all rules in plain language. This means that each rule must:

(a) Be logically organized;

(b) Use the active voice to address readers directly;

(c) Use common, everyday words and clear language rather than jargon;

(d) Be divided into short sections and sentences; and

(e) Use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments by one of the methods listed in the "ADDRESSES" section. To better help the BLM revise the rule, your comments should be as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you find unclear, which sections or sentences are too long, the sections where you feel lists or tables would be useful, etc.

Authors

The principal authors of this proposed rule are: James Tichenor and Michael Riches of the BLM Washington Office; Sheila Mallory of the BLM New Mexico State Office, Eric Jones of the BLM Moab, Utah Field Office; David Mankiewicz of the BLM Farmington, New Mexico Field Office; and Beth Poindexter of the BLM Dickinson, North Dakota Field Office; assisted by Faith Bremner of the BLM's Division of Regulatory Affairs and by the Department of the Interior's Office of the Solicitor.

List of Subjects

43 CFR part 3160

Administrative practice and procedure; Government contracts; Indians-lands; Mineral royalties; Oil and gas exploration; Penalties; Public lands--mineral resources; Reporting and recordkeeping requirements.

43 CFR part 3170

Administrative practice and procedure; Flaring; Government contracts; Incorporation by reference; Indians-lands; Mineral royalties; Immediate assessments; Oil and gas exploration; Oil and gas measurement; Public lands--mineral resources; Reporting and record keeping requirements; Royalty-free use; Venting.

Dated: September 28, 2017.

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Katharine S. MacGregor

Acting Assistant Secretary for Land and Minerals Management

43 CFR Chapter II

For the reasons set out in the preamble, the Bureau of Land Management proposes to amend 43 CFR parts 3160 and 3170 as follows:

PART 3160 – ONSHORE OIL AND GAS OPERATIONS

1. The authority citation for part 3160 continues to read as follows:

AUTHORITY: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

2. Amend § 3162.3-1 by revising paragraph (j) introductory text to read as follows:

§ 3162.3-1 Drilling applications and plans.

* * * * *

(j) Beginning January 17, 2019, when submitting an Application for Permit to Drill an oil well, the operator must also submit a plan to minimize waste of natural gas from that

well. The waste minimization plan must accompany, but would not be part of, the Application for Permit to Drill. The waste minimization plan must set forth a strategy for how the operator will comply with the requirements of 43 CFR subpart 3179 regarding control of waste from venting and flaring, and must explain how the operator plans to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible, including an explanation of why any delay in capture of the associated gas would be required. Failure to submit a complete and adequate waste minimization plan is grounds for denying or disapproving an Application for Permit to Drill. The waste minimization plan must include the following information:

* * * * *

PART 3170—ONSHORE OIL AND GAS PRODUCTION

3. The authority citation for part 3170 continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

4. Amend § 3179.7 by revising paragraphs (b) and (c) to read as follows:

§ 3179.7 Gas capture requirement.

* * * * *

(b) Beginning January 17, 2019, the operator's capture percentage must equal:

(1) For each month during the period from January 17, 2019, to December 31, 2020: 85 percent;

(2) For each month during the period from January 1, 2021, to December 31, 2023: 90 percent;

(3) For each month during the period from January 1, 2024, to December 31, 2026: 95 percent; and

(4) For each month beginning January 1, 2027: 98 percent.

(c) The term "capture percentage" in this section means the "total volume of gas captured" over the "relevant area" divided by the "adjusted total volume of gas produced" over the "relevant area."

(1) The term "total volume of gas captured" in this section means: for each month, the volume of gas sold from all of the operator's development oil wells in the relevant area plus the volume of gas from such wells used on lease, unit, or communitized area in the relevant area.

(2) The term "adjusted total volume of gas produced" in this section means: the total volume of gas captured over the month *plus* the total volume of gas flared over the month from high pressure flares from all of the operator's development oil wells that are in production in the relevant area, *minus*:

(i) For each month from January 17, 2019, to December 31, 2019: 5,400 Mcf times the total number of development oil wells "in production" in the relevant area;

(ii) For each month from January 1, 2020, to December 31, 2020: 3,600 Mcf times the total number of development oil wells in production in the relevant area;

(iii) For each month from January 1, 2021, to December 31, 2021: 1,800 Mcf times the total number of development oil wells in production in the relevant area; and

(iv) For each month from January 1, 2022, to December 31, 2022: 1,500 Mcf times the total number of development oil wells in production in the relevant area;

(v) For each month from January 1, 2023, to December 31, 2024: 1,200 Mcf times the total number of development oil wells in production in the relevant area;

(vi) For each month from January 1, 2025, to December 31, 2025: 900 Mcf times the total number of development oil wells in production in the relevant area; and

(vii) For each month after January 1, 2026: 750 Mcf times the total number of development.

* * * * *

5. Amend § 3179.9 by revising paragraph (b)(1) introductory text to read as follows:

§ 3179.9 Measuring and reporting volumes of gas vented and flared.

* * * * *

(b) * * *

(1) If the operator estimates that the volume of gas flared from a high pressure flare stack or manifold equals or exceeds an average of 50 Mcf per day for the life of the flare, or the previous 12 months, whichever is shorter, then, beginning January 17, 2019, the operator must either:

* * * * *

6. Amend § 3179.10 by revising paragraph (a) to read as follows:

§ 3179.10 Determinations regarding royalty-free flaring.

(a) Approvals to flare royalty free, which are in effect as of January 17, 2017, will continue in effect until January 17, 2019.

* * * * *.

7. Amend § 3179.101 by adding paragraph (c) to read as follows:

§ 3179.101 Well drilling.

* * * * *

(c) The operator must comply with this section beginning January 17, 2019.

8. Amend § 3179.102 by adding paragraph (e) to read as follows:

§ 3179.102 Well completion and related operations.

*** * * * ***

(e) The operator must comply with this section beginning January 17, 2019.

9. Amend § 3179.201 by revising paragraph (d) to read as follows:

§3179.201 Equipment requirements for pneumatic controllers.

*** * * * ***

(d) The operator must replace the pneumatic controller(s) by January 17, 2019, as required under paragraph (b) of this section. If, however, the well or facility that the pneumatic controller serves has an estimated remaining productive life of 3 years or less from January 17, 2017, then the operator may notify the BLM through a Sundry Notice and replace the pneumatic controller no later than 3 years from January 17, 2017.

* * * * *

10. Amend § 3179.202 by revising paragraph (h) to read as follows:

§ 3179.202 Requirements for pneumatic diaphragm pumps.

* * * * *

(h) The operator must replace the pneumatic diaphragm pump(s) or route the exhaust gas to capture or to a flare or combustion device by January 17, 2019, except that if the operator will comply with paragraph (c) of this section by replacing the pneumatic diaphragm pump with a zero-emission pump and the well or facility that the pneumatic diaphragm pump serves has an estimated remaining productive life of 3 years or less

from January 17, 2017, the operator must notify the BLM through a Sundry Notice and replace the pneumatic diaphragm pump no later than 3 years from January 17, 2017.

* * * * *

11. Amend § 3179.203 by revising paragraph (b) and paragraph (c) introductory text to read as follows:

§ 3179.203 Storage vessels.

* * * * *

(b) Beginning January 17, 2019, and within 30 days after any new source of production is added to the storage vessel after January 17, 2019, the operator must determine, record, and make available to the BLM upon request, whether the storage vessel has the potential for VOC emissions equal to or greater than 6 tpy based on the maximum average daily throughput for a 30-day period of production. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority that limit the VOC emissions to less than 6 tpy.

(c) If a storage vessel has the potential for VOC emissions equal to or greater than 6 tpy under paragraph (b) of this section, by January 17, 2019, or by January 17, 2020, if the operator must and will replace the storage vessel at issue in order to comply with the requirements of this section, the operator must:

* * * * *

12. Amend § 3179.204 by adding paragraph (i) to read as follows:

§ 3179.204 Downhole well maintenance and liquids unloading.

* * * * *

(i) The operator must comply with this section beginning January 17, 2019.

13. Amend § 3179.301 by revising paragraph (f) to read as follows:

§ 3179.301 Operator responsibility.

* * * * *

(f) The operator must make the first inspection of each site:

(1) By January 17, 2019, for all existing sites;

(2) Within 60 days of beginning production for new sites that begin production after January 17, 2019; and

(3) Within 60 days of the date when an existing site that was out of service is brought back into service and re-pressurized after January 17, 2019.

* * * * *

[FR Doc. 2017-21294 Filed: 10/4/2017 8:45 am; Publication Date: 10/5/2017]

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

STATE OF CALIFORNIA, et al., Plaintiffs, v. BUREAU OF LAND MANAGEMENT, et al., Defendants.	Case Nos. 17-cv-07186-WHO; 17-cv-07187-WHO **ORDER DENYING MOTION TO TRANSFER VENUE AND GRANTING PRELIMINARY INJUNCTION**
SIERRA CLUB, et al., Plaintiffs, v. RYAN ZINKE, in his official capacity as Secretary of the Interior, et al., Defendants.	

INTRODUCTION

This case addresses the burden a federal agency bears when it seeks to suspend a federal regulation for further analysis. Plaintiffs, the States of California and New Mexico, bring this action for a preliminary injunction enjoining the United States Bureau of Land Management ("BLM"), Katherine S. Macgregor, Acting Assistant Secretary for Land and Minerals Management, and Ryan Zinke, Secretary of the Interior, from instituting a rule suspending or delaying the requirements of the Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule. A coalition of 17 conservation and tribal citizen groups separately brought

suit for a preliminary injunction against Zinke, the BLM, and the United States Department of the Interior seeking the same preliminary injunction. These two cases have been consolidated for review.

The States of North Dakota and Texas, along with three industry groups, the Western Energy Alliance ("WEA"), Independent Petroleum Association of America ("IPAA"), and American Petroleum Institute ("API"), have moved to intervene in these consolidated actions in opposition to the preliminary injunction. The BLM and the States of North Dakota and Texas have also moved to transfer venue of this case to the District of Wyoming, where a case challenging the underlying rule is pending.[1]

First, I deny the motion to change venue. As discussed below, the legal issues concerning the Waste Prevention Rule in the District of Wyoming go to the substance of that regulation; this lawsuit addresses the BLM's alleged procedural failure to justify a different rule, the Suspension Rule. The legal issues are distinct. In light of plaintiffs' choice of forum, venue is appropriate here.

Second, I grant Plaintiffs' motion for a preliminary injunction. The BLM's reasoning behind the Suspension Rule is untethered to evidence contradicting the reasons for implementing the Waste Prevention Rule, and so plaintiffs are likely to prevail on the merits. They have shown irreparable injury caused by the waste of publicly owned natural gas, increased air pollution and associated health impacts, and exacerbated climate impacts. Plaintiffs are entitled to a preliminary injunction on this record.

BACKGROUND

On November 18, 2016, after three years of development, the BLM published the final version of its regulations intended "to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian (other than Osage Tribe) leases." *See* "Waste Prevention, Production Subject to Royalties, and Resource

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[1] "Plaintiffs" refers to the States of California and New Mexico as well as all 17 conservation and tribal citizen groups collectively. "BLM" refers to the named government defendants in both actions. "Defendants" refers to the named defendants in both actions as well as the proposed intervenors collectively.

Conservation: Final Rule," 81 Fed. Reg. 83,008 (Nov. 18, 2016) ("Waste Prevention Rule"). The Waste Prevention Rule became effective on January 17, 2017, with many of its requirements to be phased in over time up until January 17, 2018.

In November of 2016, two industry groups, the Western Energy Alliance and the Independent Petroleum Association of America, as well as the states of Wyoming and Montana, separately filed lawsuits challenging the Waste Prevention Rule and seeking a preliminary injunction in the U.S. District Court for the District of Wyoming. *See W. Energy All. v. Zinke*, No. 16-cv-0280 (D. Wyo. filed Nov. 15, 2016); *Wyoming v. U.S. Dep't of Interior*, No. 16-cv-0285 (D. Wyo. filed Nov. 18, 2016). The two cases were consolidated, and the states of California and New Mexico, as well as a coalition of environmental groups, including all but one of the plaintiffs in this action, intervened in the lawsuits on the side of the government. The States of North Dakota and Texas intervened on the side of the petitioners. On January 16, 2017, the court denied the motions for preliminary injunction. *See Wyoming v. U.S. Dep't of Interior*, Nos. 16-cv-0285, 16-cv-0280, 2017 WL 161428 (D. Wyo. Jan. 16, 2017).

On March 28, 2017, President Trump issued an Executive Order requiring the Secretary of the Interior to review the Waste Prevention Rule. Exec. Order No. 13,783, 82 Fed. Reg. 16,093, § 7(b) (Mar. 28, 2017). BLM reviewed the rule and drafted a proposed Revision Rule rescinding certain provisions of the Waste Prevention Rule and substantially revising others. BLM published the proposed rule in the Federal Register today, after conclusion of its review by the Office of Information and Regulatory Affairs. *See* "Waste Prevention, Production Subject to Royalties, and Resource Conservation: Rescission or Revision of Certain Requirements," 83 Fed. Reg. 7924 (proposed Feb. 22, 2018).

In the interim, BLM developed a rule to delay for one year the effective date of the provisions of the Waste Prevention Rule that had not yet become operative and suspend for one year the effectiveness of certain provisions already in effect ("Suspension Rule").[2] 82 Fed. Reg.

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[2] The parties have used various naming conventions in reference to the Waste Prevention Rule and the Suspension Rule. They shall adopt these two naming conventions for purposes of this litigation.

58,050, 58,051 (Dec. 8, 2017). BLM published the proposed Suspension Rule on October 5, 2017, and on December 8, 2017, published the final Suspension Rule. *See* 82 Fed. Reg. 46,458, 58,050. It took effect on January 8, 2018. The rule temporarily suspended or delayed certain requirements at the heart of the pending *Wyoming* litigation.

Plaintiffs in this action filed suit challenging the Suspension Rule on December 18, 2017, and moving for a preliminary injunction. *California v. BLM*, No. 17-cv-07186 (N.D. Cal. filed Dec. 19, 2017); *Sierra Club v. Zinke*, No. 17-cv-07187 (N.D. Cal. filed Dec. 19, 2017). On December 29, 2017, the court in the *Wyoming* cases stayed those cases in light of the Suspension Rule and BLM's continued efforts to revise the Waste Prevention Rule, as well as the present lawsuits, which raise procedural challenges to the Suspension Rule and seek to reinstate the Waste Prevention Rule. *Wyoming*, Nos. 16-cv-0280, 16-cv-0285 (D. Wyo. Dec. 29, 2017) [Dkt. Nos. 184, 189]. In that decision, the court explained that "it is fair to say those actions are inextricably intertwined with the cases before this Court and with the ultimate rules to be enforced." *Id*. at 4.

LEGAL STANDARD

I. Transfer of Venue

A court may transfer an action to another district "where it might have been brought" "[f]or the convenience of the parties and witnesses, in the interest of justice." 28 U.S.C. § 1404(a). A motion for transfer lies within the broad discretion of the district court and must be determined on an individualized basis. *Jones v. GNC Franchising, Inc*., 211 F.3d 495, 498 (9th Cir. 2000). Section 1404(a) requires the court to make a threshold determination of whether the case could have been brought where the transfer is sought. If venue is appropriate in the alternative venue, the court must weigh the convenience of the parties, the convenience of the witnesses, and the interest of justice. *See* 28 U.S.C. § 1404(a). In making its determination, the court may consider several factors, including: "(1) the location where the relevant agreements were negotiated and executed, (2) the state that is most familiar with the governing law, (3) the plaintiff's choice of forum, (4) the respective parties' contacts with the forum, (5) the contacts relating to the plaintiff's cause of action in the chosen forum, (6) the differences in the costs of litigation in the two forums, (7) the availability of compulsory process to compel attendance of

unwilling non-party witnesses, and (8) the ease of access to sources of proof." *Jones*, 211 F.3d at 498–99.

"The burden is on the party seeking transfer to show that when these factors are applied, the balance of convenience clearly favors transfer." *Lax v. Toyota Motor Corp.*, 65 F. Supp. 3d 772, 776 (N.D. Cal. 2014) (citing *Commodity Futures Trading Comm'n v. Savage*, 611 F.2d 270, 279 (9th Cir. 1979)). "The defendant must make a strong showing of inconvenience to warrant upsetting the plaintiff's choice of forum." *Decker Coal Co. v. Commonwealth Edison Co.*, 805 F.2d 834, 843 (9th Cir. 1986).

II. Preliminary Injunction

In order to obtain a preliminary injunction, a plaintiff must demonstrate four factors: (1) "that he is likely to succeed on the merits," (2) "that he is likely to suffer irreparable harm in the absence of preliminary relief," (3) "that the balance of equities tips in his favor," and (4) "that an injunction is in the public interest." *Winter v. Nat. Res. Def. Council, Inc.*, 555 U.S. 7, 20 (2008). While this is a four-part conjunctive test, the Ninth Circuit has held that a plaintiff may also obtain an injunction if it has demonstrated "serious questions going to the merits," that the balance of hardship "tips sharply" in its favor, that it is likely to suffer irreparable harm, and that an injunction is in the public interest. *See All. for the Wild Rockies v. Cottrell*, 632 F.3d 1127, 1131–35 (9th Cir. 2011). Injunctive relief is "an extraordinary remedy that may only be awarded upon a clear showing that the plaintiff is entitled to such relief." *Winter*, 555 U.S. at 22.

DISCUSSION

I. Motion to Transfer Venue

The parties do not dispute that the District of Wyoming is a proper venue where this action could have been brought. Instead, they dispute how the convenience and interest of justice factors should be weighed. For the following reasons, I conclude that Defendants have not met their burden to show that the balance of all of the relevant factors clearly favors transfer such that I should upset Plaintiffs' choice of forum in this district.

A. Convenience of the Parties and Witnesses

Defendants' primary argument in support of the "convenience" factors is that litigating this

case in the District of Wyoming would be more convenient because it would allow both the preceding *Wyoming* cases and this action to be litigated "in a coordinated fashion." *See Elecs. for Imaging, Inc. v. Tesseron, Ltd.*, No. 07-cv-05534 CRB, 2008 WL 276567, at *2 (N.D. Cal. Jan. 29, 2008). They point to *Electronics for Imaging*, in which a lawsuit was filed in the District of Ohio raising a patent infringement claim based on two patents. One of the defendants in that action filed a second suit in the Northern District of California for declaratory relief, seeking to determine its rights to those two (among other) patents. The Hon. Charles R. Breyer transferred the second suit to the District of Ohio, reasoning that "the pertinent question is not simply whether *this* action would be more conveniently litigated in Ohio than California, but whether it would be more convenient to litigate the California and Ohio actions separately or in a coordinated fashion." *Id*.

Those two cases each raised the issue of the parties' rights under the same two patents. This matter shares no identical issues with the *Wyoming* cases. It is true that the cases pertain to related rules, but the legal issues are distinct. *Wyoming* concerns a challenge to the Waste Prevention Rule in which the petitioners argue that BLM exceeded its authority by impermissibly encroaching on both the EPA's authority to regulate air pollution and states' regulatory authority over certain state lands, as well as that the Waste Prevention Rule is arbitrary and capricious because its cost-benefit analysis takes into consideration air pollution benefits rather focusing on waste prevention. The matter here deals with the procedural propriety of the Suspension Rule under the APA, and whether the Suspension Rule is arbitrary and capricious because, among other reasons, it does not provide the requisite detailed justification for relying on inconsistent and contradictory facts to its prior findings. This matter does not deal with any issues regarding BLM's authority to regulate air pollution, as is the focus of the *Wyoming* litigation. As the cases share no identical legal issues, there is no substantial convenience in litigating them "in a coordinated fashion" as there was in *Electronics for Imaging*. While the disposition of this matter may affect the proceedings in the *Wyoming* cases, the court's issuance of the stay in that litigation ensures that the *Wyoming* court is not wasting judicial resources or coming to a premature decision pending the outcome of this litigation.

Defendants' remaining contentions in support of the convenience factors amount to arguments that Plaintiffs cannot show that the Northern District of California is a more convenient forum. That is not Plaintiffs' burden. Defendants must show that the convenience of the parties and the witnesses favors the District of Wyoming. Defendants assert that Plaintiffs' California connections are limited and tempered by their voluntary participation in the *Wyoming* litigation, that the Northern District of California is less convenient for Defendants than the District of Wyoming, and that Wyoming has just as much interest in and ties to these cases as California. Defendants' first and third points are true but not relevant to the question of convenience. That most of the plaintiffs in this matter are litigating a case in the District of Wyoming does not somehow mean that litigating a second case there is not an additional burden or inconvenience to them. Defendants' arguments boil down to the District of Wyoming being more convenient for themselves only, due to the cost of litigating a second set of cases in this district. The transfer of venue, however, "would merely shift rather than eliminate the inconvenience" from Defendants to Plaintiffs. *Decker Coal*, 805 F.2d at 843. This is insufficient to show that the convenience of the parties and witnesses weighs in favor of transferring the case to the District of Wyoming.

B. Interest of Justice

Defendants argue that the interest of justice heavily favors transfer of these cases because of the strong interest in having a single court review issues arising out of the same rulemaking, emphasizing the District of Wyoming's familiarity with the Waste Prevention Rule. They urge the court to focus its attention on this analysis because "[t]he question of which forum will better serve the interest of justice is of predominant importance on the question of transfer, and factors involving convenience of parties and witnesses are in fact subordinate." *Wireless Consumers All., Inc. v. T-Mobile USA, Inc.*, No. 03-cv-3711-MHP, 2003 WL 22387598, at *4 (N.D. Cal. Oct. 14, 2003). In opposition, Plaintiffs argue that Defendants mischaracterize the relationship between the two actions, and that none of the legal issues before the *Wyoming* court are before this one.

As discussed above, this case and the *Wyoming* litigation involve separate legal issues. That the subject matter at the heart of both of these actions is the same is hardly grounds for transfer. Indeed, many cases may arise from a single rule or statute. But Section 1404(a) "was

designed to prevent" "a situation in which two cases involving *precisely the same issues* are simultaneously pending in different District Courts." *Elecs. for Imaging*, 2008 WL 276567, at *1 (emphasis added). It is not enough that these cases deal with and require me to become familiar with the substance of the Waste Prevention Rule; instead, Defendants must show that the two cases present the same legal questions so that litigating them separately would be a waste of judicial resources. This Defendants cannot do.

Defendants make much of the *Wyoming* court's statement that these two cases are "inextricably intertwined." *Wyoming*, Nos. 16-cv-0280, 16-cv-0285 (D. Wyo. Dec. 29, 2017) [Dkt. Nos. 184, 189] at 4. For purposes of the *Wyoming* court's decision to issue the stay, I agree that the resolution of this litigation is "inextricably intertwined . . . with the ultimate rules to be enforced" because the resolution here determines the timing of the effectiveness of the Waste Prevention Rule's provisions, and therefore which provisions the *Wyoming* court will review and the ripeness of those cases. While the cases can be said to be inextricably intertwined due to the implications on timing and effectiveness of the Waste Prevention Rule's provisions, they are otherwise substantively distinct, and the challenges to each raise unique legal questions and require the evaluation of two separate rules promulgated for different reasons.

Given the distinctions between the two cases, Defendants' arguments regarding the threat of "inconsistent judgments" are unfounded because this litigation does not require an evaluation of the Waste Prevention Rule. Defendants argue that disposition in this case will necessarily require me to review the underlying Waste Prevention Rule and evaluate its substantive provisions, as it serves as the benchmark by which the Suspension Rule will be judged. While it is true that I must review the Waste Prevention Rule insofar as I am required to determine whether, for example, the Suspension Rule rests on factual findings that contradict those underlying the Waste Prevention Rule, that is the extent to which I am required to review the Waste Prevention Rule. I need not evaluate the merits of its substance or the persuasiveness or propriety of its justifications. Indeed, I express no judgment whatsoever in this opinion on the merits of the Waste Prevention Rule. Instead, I need only look to see whether any contradictions exist between the two rules, and if so, whether the Suspension Rule provides the necessary detailed justification for such a contradiction.

For that reason, this case is distinguishable from *Bay.org v. Zinke*, Nos. 17-CV-03739-YGR, 17-CV-3742-YGR, 2017 WL 3727467 (N.D. Cal. Aug. 30, 2017). In that case, an initial suit was filed in the Eastern District of California in 2005 challenging the United States Fish and Wildlife Service's ("FWS") biological opinions supporting two water projects, which plaintiffs alleged would harm the delta smelt. *Id.* at *2. A separate case was filed in 2017 in the Northern District of California challenging the biological opinion underpinning a new FWS water project, which plaintiffs alleged "[wa]s the latest in a long line of water diversion projects and policies, including the [earlier two projects], which have had devastating effects" on the delta smelt. *Id.* at *3. Those cases required the court to make substantive determinations regarding the biological opinions for three related water projects in the same region, all challenged on similar grounds, and plaintiffs in both cases sought "an order instructing the FWS to reinstate consultation with the relevant organizations to develop different plans." *Id.* at *5. Thus, there was both "overlap in the issues" and a serious possibility for "inconsistent rulings," a concern that is not present in the instant case. Furthermore, it was more efficient for the court to promote "[c]onsistency with respect to the nature and scope of [the sought] consultations, if any." *Id.* Here, the remedy that Plaintiffs seek does not require any coordination with the *Wyoming* case.

Nor would transferring these actions aid judicial efficiency. The *Wyoming* court has already stayed those cases pending the outcomes here, and the most efficient and expedient option is for this court to proceed with the motions for preliminary injunctions, which are fully briefed and ripe for review. Granting Defendants' transfer would require refiling of all the briefing and setting of a new hearing date in the District of Wyoming, incurring delay and contributing to Plaintiffs' alleged irreparable harm.

C. Plaintiffs'' Choice of Forum

An important additional factor is the plaintiff's choice of forum.[3] Although it is not a statutory requirement, the Supreme Court has placed a strong emphasis on the plaintiff's choice of forum. *See Piper Aircraft Co. v. Reyno*, 454 U.S. 235, 255 (1981) ("[T]here is ordinarily a strong

[3] The parties agree that the other factors are irrelevant or neutral.

presumption in favor of the plaintiff's choice of forum, which may be overcome only when the private and public interest factors clearly point towards trial in the alternative forum."); *see also Ravelo Monegro v. Rosa*, 211 F.3d 509, 513 (9th Cir. 2000) (noting the "strong presumption in favor of a domestic plaintiff's forum choice"); *Ctr. for Biological Diversity v. McCarthy*, No. 14-cv-05138-WHO, 2015 WL 1535594, at *3 (N.D. Cal. Apr. 6, 2015) (plaintiff's" choice of forum receives substantial deference, especially when the forum is within the plaintiff's home district or state") (citing *Lou v. Belzberg*, 834 F.2d 730, 739 (9th Cir. 1987)).

This forum is home to the State of California, a state sovereign, which contains a significant amount of land that stands to be affected by the outcome of this litigation. While Defendants argue that the State of Wyoming has a larger amount of federal and Indian oil and gas development impacted by the Suspension Rule, this does not diminish California's real interest. *See* Mot. at 15 ("[T]he federal minerals in the entire State of California produced 11.5 million barrels of oil and 12.2 billion cubic feet (Bcf) of natural gas."). The State of Wyoming has not sought to intervene in these cases to protect its interests.

Because Defendants have not shown that the convenience or interest of justice factors weigh strongly in favor of transfer, I will not disturb Plaintiffs' choice of venue. The most expedient result is for the case to remain in this district. Defendants' motion for transfer of venue to the District of Wyoming is DENIED.

II. Motion for Preliminary Injunction

Plaintiffs move for a preliminary injunction enjoining BLM from enforcing the Suspension Rule, effectively putting the Waste Prevention Rule back into place and requiring immediate compliance. While the parties dispute all of the elements of the preliminary injunction analysis, the most rigorous arguments focus on and the most challenging questions arise under Plaintiffs' likelihood of success on the merits. Plaintiffs raise several challenges to BLM's justifications for the Suspension Rule, contending that it is not supported by a reasoned analysis and is therefore arbitrary and capricious. These challenges, along with the arguments regarding irreparable harm, the balance of equities, and the public interest, will each be addressed in turn.

United States District Court
Northern District of California

A. Likelihood of Success on the Merits

"The Administrative Procedure Act, 5 U.S.C. § 551 et seq., [] sets forth the full extent of judicial authority to review executive agency action for procedural correctness . . . ." *F.C.C. v. Fox Television Stations, Inc*., 556 U.S. 502, 513 (2009). It permits a reviewing court to "hold unlawful and set aside agency action, findings, and conclusions found to be" either "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706. Under this standard of review, an agency must "examine the relevant data and articulate a satisfactory explanation for its action." *Motor Vehicle Mfrs. Ass'n of United States, Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983). Agency action is "arbitrary and capricious if the agency has . . . offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Id*. "[A] court is not to substitute its judgment for that of the agency." *Fox Television Stations*, 556 U.S. at 513.

When an agency takes an action that represents a policy change, it "must show that that there are good reasons for the new policy," "[b]ut it need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one; it suffices that the new policy is permissible under the statute [and] that there are good reasons for it . . . ." *Fox Television Stations*, 556 U.S. at 515. The Supreme Court has advised that "when, for example, [an agency's] new policy rests upon factual findings that contradict those which underlay its prior policy," the agency must "provide a more detailed justification than what would suffice for a new policy created on a blank state." *Id*. at 515; *see also Nat'l Cable & Telecomms. Ass'n v. Brand X Internet Servs*., 545 U.S. 967, 981 (2005) ("Unexplained inconsistency" between agency actions is "a reason for holding an interpretation to be an arbitrary and capricious change."). "In such cases it is not that further justification is demanded by the mere fact of the policy change; but that a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy." *Fox Television Stations*, 556 U.S. at 515–16; *see also Action for Children's Television v. F.C.C.*, 821 F.2d 741, 745 (D.C. Cir. 1987) ("It is axiomatic that an agency choosing to alter its regulatory course must supply a reasoned analysis indicating its prior

policies and standards are being deliberately changed, not casually ignored.”).

BLM argues that Plaintiffs conflate the Suspension Rule with the proposed future revision of the Waste Prevention Rule. I agree that I must analyze the Suspension Rule as a discrete agency action separate from any proposed future revision. Because BLM has yet to pass any future revision, its substance, validity, and procedural proprietary are not before this Court. But reviewing the Suspension Rule as a discrete action cuts both ways; while Plaintiffs may not conflate it with any future feared revision, BLM cannot use the purported proposed future revision, which has yet to be passed, as a justification for the Suspension Rule.

Any suggestion, however, that the Suspension Rule should be reviewed with less rigor than any future revision has no merit. *See Fox Television Stations*, 556 U.S. at 515. As BLM agrees with Plaintiffs that the Suspension Rule represents a substantive change in policy, *see* Opp. at 17, it is subject to the standard of review outlined by the Supreme Court in *Fox Television Stations*. BLM does not have to provide the same reasoned analysis in support of a temporary suspension that it would for a future substantive revision, but it must nonetheless provide good reasons for the Suspension Rule. To the extent that its reasoning contradicts the reasoning underlying the Waste Prevention Rule, it must be prepared to provide the requisite good reasons and detailed justification.

Under this framework, Plaintiffs argue that BLM’s Suspension Rule is arbitrary and capricious for several reasons. First, they assert that BLM has failed to provide a reasoned analysis for the Suspension Rule because its stated rationales are not legitimate and its justifications are inconsistent with and not supported by the evidentiary record. They also criticize the 2017 Regulatory Impact Analysis (“RIA”) underpinning BLM’s cost and benefit analysis. Beyond the substance, Plaintiffs argue that the Suspension Rule is inconsistent with BLM’s statutory duties and that BLM failed to provide meaningful notice and comment to the public. Each of these arguments, and Defendants’ responses, will be considered in turn.

1. Whether BLM Provided A Reasoned Analysis for the Suspension Rule

Plaintiffs contend that BLM failed to provide a reasoned analysis with legitimate rationales and justifications supported by the record for the Suspension Rule. BLM’s primary rationale in

the Suspension Rule is that it "has concerns regarding the statutory authority, cost, complexity, feasibility, and other implications of the [Waste Prevention] rule, and therefore wants to avoid imposing temporary or permanent compliance costs on operators for requirements that might be rescinded or significantly revised in the near future." 82 Fed. Reg. at 58,050. BLM states that after an initial review of the Waste Prevention Rule in the spring of 2017, it concluded that certain provisions enacted just months earlier "add considerable regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation." *Id*.

Plaintiffs argue that this conclusion is contrary to and inconsistent with BLM's earlier finding that the Waste Prevention Rule imposes "economical, cost-effective, and reasonable measures . . . to minimize gas waste." 81 Fed. Reg. at 83,009. Because BLM's new concerns appear to rest upon factual findings that contradict those underlying its prior policy, BLM must "provide a more detailed justification than what would suffice for a new policy created on a blank slate." *Fox Television Stations*, 556 U.S. at 515.

As an example of the Waste Prevention Rule's considerable regulatory burden, BLM first points to operators of marginal or low-producing wells, explaining that "[t]here is newfound concern that this additional burden would jeopardize the ability of operators to maintain or economically operate these wells." 82 Fed. Reg. at 58,050. Plaintiffs argue, however, that BLM provides no analysis or factual data to support this concern. Reviewing the Suspension Rule's discussion of marginal wells, I agree with Plaintiffs. BLM states that it is "reconsidering whether it was appropriate to assume that all marginal wells would receive exemptions from the rule's requirements and whether the assumption might have masked adverse impacts of the [Waste Prevention Rule] on production from marginal wells." *Id*. at 58,051. The Suspension Rule provides no basis for this reconsideration and points to no facts casting doubt on this assumption.

In its briefing, BLM offers that marginal wells "are less likely to support additional compliance costs associated with the LDAR [leak detection and repair] requirements," and that these costs "could cause operators to shut-in marginal wells, thereby ceasing production and reducing economic benefits to local, State, tribal, and Federal governments," citing its 2017 Environmental Assessment in support. Opp. at 24 (internal quotation marks and citation omitted).

Yet the Environmental Assessment provides no citation or factual basis for that claim either, nor does it offer any more detail about what the additional compliance costs are, at what point they would cause shut-in of marginal wells, or the value of the supposed lost benefits. At the hearing on this matter, counsel for the government essentially conceded that it was in possession of no new facts or data underlying this "newfound" concern, but instead contended that it had no burden to point to any such data at this stage because BLM merely suspended the Waste Prevention Rule (as opposed to revoking or revising it). This is contrary to the law and the standard set forth by the Supreme Court under *Fox Television Stations*. Because BLM fails to point to any factual support underlying its concern, the marginal wells cannot serve as a justification for BLM's Suspension Rule.

BLM also expresses concern that certain provisions would have "a disproportionate impact on small operators." 82 Fed. Reg. at 58,051. Under the Waste Prevention Rule, BLM estimated "that average costs for a representative small operator would increase by about $55,200, which would result in an average reduction in profit margin of 0.15 percentage points." 81 Fed. Reg. at 83,013–14. It concluded that this impact was "small, even for businesses with less than 500 employees." *Id*. at 83,013. In the Suspension Rule, BLM's new analysis estimates "the potential reduction in compliance costs to be about $60,000," "result[ing] in an average increase in profit margin of 0.17 percentage points." 82 Fed. Reg. at 58,058. BLM also concludes, in its section evaluating the economic effect on small entities under the Regulatory Flexibility Act ("RFA"), that "the average reduction in compliance costs associated with this final delay rule will be a small fraction of a percent of the profit margin for small companies, which is not a large enough impact to be considered significant." *Id*. at 58,064.

Plaintiffs argue that there is no significant difference between the burden imposed by the Waste Prevention Rule and the reduction associated with the Suspension Rule, given that they both represent a fraction of a percentage point. BLM's characterizations of those savings concede as much. Given that, BLM's concern that small operators' ability to maintain or economically operator their wells would be jeopardized is unfounded. While BLM attempts to explain that its significance finding was "not made as a general determination that $60,000 savings is irrelevant

for a small business . . . , but rather as part of its analysis to determine whether it is required to prepare a regulatory flexibility analysis" per the RFA, Opp. at 23, the RFA requires BLM to evaluate whether a "rule would have a significant economic impact, either detrimental or beneficial, on a substantial number of small entities" so as "to ensure that government regulations do not unnecessarily or disproportionately burden small entities." 82 Fed. Reg. at 58,064. BLM does not explain how or why it could conclude that the calculated costs could be so insignificant as not to unnecessarily or disproportionately burden small entities within the meaning of the RFA, and simultaneously conclude that there would be a disproportionate effect for other purposes. Nor could it, as these two positions are entirely inconsistent. Nor does BLM attempt to show in a concrete manner how the $55,200 burden of the Waste Prevention Rule would affect small operators; BLM does not quantify how many would no longer be able to operate given the cost of compliance, nor does it provide any other metric for qualitatively evaluating the impact on small operators.[4] And even if BLM had provided such factual evidence, by itself it would not justify the Suspension Rule, as the rule is not properly tailored and does not merely suspend the Waste Prevention Rule as applied to small operators, but instead is a blanket suspension as to all operators, regardless of size. For these reasons, I agree with Plaintiffs that BLM's concerns about small operators cannot serve as a justification for the change in policy that the Suspension Rule represents.

BLM similarly expresses concern about the Waste Prevention Rule's calculation on impacts on royalties. BLM states that it is reexamining the 2016 RIA underlying the Waste Prevention Rule and its conclusion that royalty payments would increase under the Waste Prevention Rule. The basis for this reconsideration appears to be that

> [s]ome commenters were concerned that the [Waste Prevention Rule] would impact oil and gas development on tribal reservations and royalties to tribes. Some tribes are located in known shale play areas and contain large amounts of undeveloped or underdeveloped areas. In particular, the commenters suggested that the [Waste Prevention Rule] could delay drilling on or drive industry away from tribal lands, reducing income flowing to

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[4] At the hearing on this matter, Defendants urged that many of these small entities were "mom and pop shops" with fewer than 15 employees. According to BLM's "Detail of Small Businesses Impacts Analysis," the average small entity reports 181 employees, and only two of the 26 examples provided had fewer than 15 employees. *See* 2016 RIA at 183.

Indian mineral owners and tribal economies.

82 Fed. Reg. at 58,059. While these commenters' concerns might be valid, BLM does not provide any factual support for their concern, explain how the Waste Prevention Rule would result in such an impact, or attempt to calculate or even estimate any quantifiable effect on royalties. This concern is directly contradicted by the 2016 RIA, which estimated a significant increase in total royalties. *See id*. at 58,057. BLM's explanation falls short of meeting the requisite reasoned analysis, let alone the "more detailed justification" required when contradictory findings are involved. *See Fox Television Stations*, 556 U.S. at 515.

Plaintiffs further criticize the Suspension Rule for reaching conclusions in support of the Suspension Rule that contradict its stated factual findings. While BLM states that some provisions of the Waste Prevention Rule would "unnecessarily encumber energy production, constrain economic growth, and prevent job creation," 82 Fed. Reg. at 58,050, it provides no support for this claim, and later states that the Suspension Rule will not "significantly impact the price, supply or distribution of energy," nor "substantially alter the investment or employment decisions of firms," *id*. at 58,057. BLM argues that these statements are taken out of context, and instead that the Suspension Rule will not significantly impact price supply, or distribution of energy worldwide because "relative changes in production compared to global levels are expected to be small." *Id*. While this may be true, BLM does not then point to any fact that justifies its assertion that the Waste Prevention Rule encumbers energy production. Its concern remains unfounded. BLM further argues that its finding regarding employment and investment decisions of firms was based on its findings in the 2016 RIA, which are under review. While this again may be true, that simply means that as of right now, the 2016 RIA remains the most recent factual finding on that point. BLM fails to point to contradictory evidence that could support an alternate conclusion.

Perhaps the BLM's best justification for the Suspension Rule is its concern that not all of the Waste Prevention Rule's provisions will survive judicial review. *See* 82 Fed. Reg. at 58,050. BLM states that the *Wyoming* court "express[ed] concerns that the BLM may have usurped the authority of the Environmental Protection Agency (EPA) and the States under the Clean Air Act, and questioned whether it was appropriate for the Waste Prevention Rule to be justified based on

its environmental and societal benefits, rather than on its resource conservation benefits alone." *Id.*; *see also Wyoming*, 2017 WL 161428, at *8, *10. Unlike several other of BLM's concerns, this one is grounded in a federal judge's reasoned skepticism outlined in a judicial order regarding the propriety of the Waste Prevention Rule. While this concern for judicial review may serve to justify a suspension or delay of specific provisions addressed by the court in order to evaluate BLM's authority with respect to EPA's, BLM concedes that the Suspension Rule was not tailored with this in mind, but rather "tailored [] to achieve its goal of relieving operators and the agency of the burden of complying with a rule that may shortly change." Opp. at 22. To the extent that BLM's concern regarding judicial review is a legitimate one, the Suspension Rule is an inappropriate response because it is not tailored to address that issue.[5]

BLM argues that for this Court to require it to provide the necessary factual underpinnings in support of the Suspension Rule, BLM would be at risk of a predetermination challenge. BLM misunderstands its burden. It need not provide a level of analysis equivalent to the Waste Prevention Rule in support of the Suspension or equivalent to any future revision rule. But it must provide at least some basis—indeed, a "detailed justification"— to explain why it is changing course after its three years of study and deliberation resulting in the Waste Prevention Rule. New facts or evidence coming to light, considerations that BLM left out in its previous analysis, or some other concrete basis supported in the record—these are the types of "good reasons" that the law seeks. Instead, it appears that BLM is simply "casually ignoring" all of its previous findings and arbitrarily changing course. *See Action for Children's Television*, 821 F.2d at 745. Given the various concerns that contradict the factual findings underpinning the Waste Prevention Rule, and BLM's failure to provide the detailed justifications necessary to explain such contradictions in support of the Suspension Rule, Plaintiffs have shown a reasonable likelihood of success on the merits of their claim that the Suspension Rule is not grounded in a reasoned analysis and is therefore arbitrary and capricious.

[5] Indeed, if BLM had not moved in June of 2017 to extend the briefing schedule by 90 days in the Wyoming litigation, that court might have completed its review of the record and resolved the BLM's concerns in this regard.

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That said, I will continue to address all of the parties' arguments regarding Plaintiffs' likelihood of success on the merits.

2. Whether the Suspension Rule is Based on a Flawed RIA

Plaintiffs next contend that the Suspension Rule is based on a flawed RIA. They launch three attacks on the RIA to argue that because it improperly calculates the costs and benefits of the Waste Prevention Rule, the Suspension Rule is not the result of a reasoned analysis.

First, Plaintiffs argue that the BLM assumes that the Waste Prevention Rule will only be delayed for one year, then instituted in its current form, while BLM has made clear that it intends to rescind or revise most of the Waste Prevention Rule's suspended provisions. Regardless of BLM's plans or intentions, however, it has yet to pass a future revision. Neither Plaintiffs nor BLM nor I can say with any certainty, at this time, what form the future revision will take, if any. It would be improper for BLM to base its calculations on anything but what is known today.

Currently, after the year of the Suspension Rule is over, the Waste Prevention Rule is set to go back into effect in its unrevised form. For this reason, the RIA's assumption that the air quality and climate benefits of the Waste Prevention Rule will only be lost for one year is acceptable. What is not acceptable, however, is that the Suspension Rule then includes the reductions in compliance cost in its calculations of net benefits, as though such reductions would be permanent and no costs would be incurred in 2019 after the Suspension Rule expires and the Waste Prevention Rule is put into place. The BLM estimates such reductions to be between $110 to $114 million. *See* 2017 RIA at 37.

BLM cannot have it both ways: either the air quality and climate benefits will be lost indefinitely and not for only one year because the Waste Prevention Rule is not going into effect, and thus industry will never incur the compliance costs, or the air quality and climate benefits are lost for only one year, and there are no reductions in compliance cost because those costs are simply delayed for one year. BLM cannot base its calculations on inconsistent assumptions to inflate its calculation of the net benefits. Given this serious flaw, the RIA's calculation of total net benefits from 2017 to 2027, which depending on discount rate ranges from $19 to $52 million, *see id*. at 46, either deeply underestimates the lost air quality and climate benefits, or overestimates the

reduction in compliance costs. The total net figure is likely negative.

Plaintiffs' second argument is that BLM assumes without evidence in its calculations that no operators have undergone any compliance activities to meet the original January 17, 2018 deadlines under the Waste Prevention Rule, thereby likely overestimating the industry cost savings. The Waste Prevention Rule was effective on January 17, 2017, and in effect for the next five months before BLM attempted to postpone the rule on June 15, 2017. BLM responds that "[t]here is not [] a public count of operators who have not complied with the Waste Prevention] Rule, rendering a precise estimate of compliance cost savings elusive," and thus it determined "that many operators are not poised to comply with the [Waste Prevention] Rule," calling its determination "a judgment call." Opp. at 39. But BLM does not provide any factual basis for this arbitrary assumption. Moreover, the monetary amount that operators have already spent or will need to spend in order to come into compliance is a numerical figure capable of being determined, even if neither party has taken steps to calculate that number.

Obtaining factual, objective data and values is not subject to "judgment calls." Judgment calls are for the determination of subjective values, such as what the "best" course of action is or what constitutes reasonable doubt. Contrary to BLM's assertion, its baseless calculation of industry cost savings is not a "judgment call" entitled to deference, but rather an estimated figure that lacks a reasonable basis.

Plaintiffs' third attack on the 2017 RIA concerns BLM's failure to consider the global costs of increased methane emissions, which Plaintiffs characterize as effectively dismissing 90 percent of the associated costs. Cal. Mot. at 21. BLM justifies this change for two reasons. First, BLM argues that Executive Order 13783 directed agencies to ensure their analyses are consistent with the guidance in the Office of Management and Budget ("OMB") Circular A-4, which emphasizes that any regulatory analysis "should focus on benefits and costs that accrue to the citizens and residents of the United States." While Plaintiffs argue that the same Circular directs BLM to encompass "all the important benefits and costs likely to result from the rule," including "any important ancillary benefits," it does not specifically mandate that agencies consider global impacts. BLM also explains that since the 2016 RIA, "Section 5 of Executive Order 13793

withdrew the technical support documents on which the 2016 RIA relied for the valuation of the changes in methane emissions using a global metric." Opp. at 39. BLM has a broad mission and is in a better position than the plaintiffs to consider what constitutes an "important" benefit. It has provided a factual basis for its change in position (the OMB circular and Executive Order 13793) as well as demonstrated that the change is within its discretion, at least with respect to this aspect of the RIA.

While not all of Plaintiffs' criticisms of the 2017 RIA have merit, Plaintiffs are correct that its estimated cost savings is likely seriously inflated due to the flawed and inconsistent assumptions underpinning the compliance cost calculation and the reduction in compliance costs. These flaws in the RIA provide a separate reason that the Suspension Rule is not based on a reasoned analysis.

3. Whether BLM Failed to Consider Its Statutory Duties

Plaintiffs also argue that the Suspension Rule is arbitrary and capricious because BLM has "entirely failed to consider an important aspect of the problem," *State Farm*, 463 U.S. at 42–43, in this case, its mandated statutory duties to prevent waste of public natural resources. Plaintiffs point to BLM's earlier findings that "measures to conserve gas and avoid waste may significantly benefit local communities, public health, and the environment," 81 Fed. Reg. at 83,009, as well as that its existing regulations, dating back to 1979, were "not particularly effective in minimizing waste of public minerals," *id*. at 83,017. BLM stated that it "has independent legal and proprietary responsibilities to prevent waste in the production of Federal and tribal minerals, as well as to ensure the safe, responsible, and environmentally protective use of BLM-managed lands and resources." *Id*. at 83,018. Plaintiffs characterize the Suspension Rule, on the other hand, as undermining BLM's statutory duties without explanation, ignoring the reasons articulated for promulgation of the Waste Prevention Rule.

BLM counters that the Suspension Rule is an exercise of its broad authority, under the Mineral Leasing Act of 1920, Federal Oil and Gas Royalty Management Act of 1982, and Indian Mineral Leasing Act of 1938, which grant BLM broad authority to manage mineral development on public and Indian lands. Opp. at 27–28. Its directive under these statutes is not solely to

prevent waste of resources, but also "to promote the orderly development of the oil and gas deposits in the publicly owned lands of the United States through private enterprise." *Harvey v. Udall*, 384 F.2d 883, 885 (10th Cir. 1967) (citing S. Subcomm. of the Comm. on Interior & Insular Affairs, The Investigation of Oil and Gas Lease Practices, 84th Cong., 2d Sess. 2 (1957)). BLM points to other responsibilities as well, including to "ensure that Indian tribes receive the maximum benefit from mineral deposits on their lands," *Jicarilla Apache Tribe v. Supron Energy Corp.*, 728 F.2d 1555, 1568 (10th Cir. 1984), to protect "the safety and welfare of workers," 30 U.S.C. § 187, to ensure minerals produced on public lands are sold "to the United States and to the public at reasonable prices," *id.*, "to diversify and expand the Nation's onshore leasing program to ensure the best return to the Federal taxpayer," 30 U.S.C. §226(b)(1)(C), and others. It argues that it has been delegated the authority to balance its broad range of responsibilities and is in the best position to evaluate how to weigh competing concerns.

I agree with BLM that given its range of statutorily-mandated duties and responsibilities, it is best suited to evaluate its competing options and choose a course of action. The Suspension Rule, when considered as a discrete action and without guessing as to the content of any future proposed revision, does not necessarily represent an abdication of BLM's duty to prevent waste. Its effect is to delay the Waste Prevention Rule's provisions for one year, at which point the Rule is set to go into effect. Thus, Plaintiffs' contention that the Suspension Rule is arbitrary and capricious because it does not consider BLM's statutory duties fails. Simply because BLM does not fulfill its statutory duties in the manner that Plaintiffs would prefer does not mean that it failed to consider them.

4. **Whether BLM Has Prevented Meaningful Comment on the Suspension Rule**

Plaintiffs finally argue that the Suspension Rule is unlawful because it violates the basic requirement that agencies allow for meaningful comment on their proposed rules. *See* 5 U.S.C. § 553(c); *Idaho Farm Bureau Fed'n v. Babbitt*, 58 F.3d 1392, 1404 (9th Cir. 1995) ("The purpose of the notice and comment requirements is to provide for meaningful public participation in the rule-making process."). Plaintiffs argue that the notice and comment in this case was not meaningful

because Secretary Zinke had already determined the outcome of the rulemaking before receiving comment and limited the scope of the rulemaking comments so as not to consider those addressing the substance of the Waste Prevention Rule or Suspension Rule.

BLM responds that "predetermination" is a high standard, citing cases arising in the context of environmental impact reviews under the National Environmental Protection Act ("NEPA"). *See* Opp. at 33. BLM cites no cases showing that this standard for predetermination, however, has ever been applied outside the context of NEPA environmental impact reviews. Instead, other circuit courts have evaluated whether comment was meaningful by evaluating whether an agency "remained 'open-minded' about the issues raised and engage[d] with the substantive responses submitted." *Prometheus Radio Project v. F.C.C.*, 652 F.3d 431, 453 (3d Cir. 2011) (internal citations omitted); *Rural Cellular Ass'n v. F.C.C.*, 588 F.3d 1095, 1101 (D.C. Cir. 2009) ("The opportunity for comment must be a meaningful opportunity, and we have held that in order to satisfy this requirement, an agency must also remain sufficiently open-minded.") (internal citations omitted).[6]

In *Prometheus Radio Project*, for example, the Third Circuit concluded that an agency did not keep the requisite open mind where a draft of the proposed rule was circulated internally two weeks before the comment period closed and before most of the comments were received, and the final vote occurred within a week of the response deadline. 652 F.3d at 453. In contrast, in *Rural Cellular*, the D.C. Circuit noted that the agency "compiled a record that included 113 sets of comments from interested parties, considered those comments" by properly taking the views of both supporters and critics into account and responding to specific critiques of the rule in the final order, and "did not issue the Order until the required rulemaking was complete. Nothing else is

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[6] While these formulations are similar to that in *Nehemiah Corp. of Am. v. Jackson*, 546 F. Supp. 2d 830, 847 (E.D. Cal. 2008), which Plaintiffs cite in support of their argument, these cases are more directly on point because they deal specifically with the meaningfulness of the comment period under the APA, whereas *Nehemiah* and the authority it cites discuss disqualification of an official for prejudgment. As the issue of disqualification is not presently before me, I follow the standards expressed by *Prometheus Radio Project* and *Rural Cellular*. It is nonetheless worth noting, however, that in *Nehemiah*, the court explained that "[m]ere proof that the official has taken a public position, or has expressed strong views, or holds an underlying philosophy with respect to an issue in dispute is not enough to overcome the presumption that an official is objective and fair." 546 F. Supp. 2d at 847 (internal quotation marks and citation omitted).

required." 588 F.3d at 1101.

In this case, BLM has followed the required procedures and addressed specific comments in support of and in opposition to the Suspension Rule in an 89-page response. Nothing in the timeline of its process shows an impermissible predetermination or closed mindedness, as was the case in *Prometheus Radio Project*. Nor does the response to the comments suggest that BLM simply ignored the public participation in the deliberative process.

Plaintiffs' argument regarding the Secretary's limitation of the scope of the comments, however, has more merit. Secretary Zinke refused to consider comments regarding the substance or merits of the Waste Prevention Rule, determining that they were outside the scope of the Prevention Rule. For example, Secretary Zinke deemed comments asserting that the Waste Prevention Rule did not burden industry given companies' financial performance and job growth as outside the scope of the Suspension Rule. These comments, however, bear directly upon the Secretary's stated rationales for the Suspension Rule; indeed, the Suspension Rule explains that "[o]perators have raised concerns regarding the cost, complexity, and other implications of [the Waste Prevention Rule]." 82 Fed. Reg. at 58,058. The Secretary cannot, on the one hand, use concerns about cost and complexity to industry as a justification for the Suspension Rule, only to deny comments about the financial and economic burden to industry as outside the scope of the Suspension Rule, on the other.

Similarly, the Suspension Rule repeatedly expresses concerns that the Waste Prevention Rule is unnecessarily burdensome on industry, but the Secretary excluded comments that the Waste Prevention Rule "is not burdensome to operators because jobs have not been lost and [] drilling activity is increasing." Opp. at 34–35 (internal quotation marks and citations omitted). The relevant burden of the Waste Prevention Rule cannot serve as a justification for the Suspension Rule and yet at the same time be outside the scope for purposes of comment. While his actions in this case are certainly not as egregious those in *North Carolina Growers' Ass'n, Inc. v. United Farm Workers*, 702 F.3d 755, 769 (4th Cir. 2012), the matters that the Secretary refused to consider were "not only 'relevant and important,' but were integral to the proposed agency action." For these reasons, the Secretary's content restrictions on the comments to the Suspension

Rule prevented meaningful comment on key justifications underpinning the Suspension Rule. That is insufficient to satisfy the APA.

Taking all parties' concerns into consideration, I agree with Plaintiffs that BLM has failed to provide the requisite reasoned analysis in support of the Suspension Rule, and it is therefore arbitrary and capricious within the meaning of the APA. BLM's contention that this result would mean that "an agency would never temporarily suspend a rule pending reconsideration—regardless of the costs imposed by the rule in the interim—because it would have to engage in the same level of analysis for the suspension as it would for any future substantive revision," Opp. at 36–37, is incorrect. Instead, I simply conclude that on the record before me, Plaintiffs are likely to succeed on their claim that BLM failed to consider the scope of commentary that it should have in promulgating the Suspension Rule and relied on opinions untethered to evidence, which is required to give a reasoned explanation to suspend the Waste Prevention Rule (that had an evidentiary basis).

B. Irreparable Harm

Plaintiffs argue that without a preliminary injunction of the Suspension Rule, they will suffer irreparable harm in the form of waste of publicly-owned natural gas, increased air pollution and related health impacts, exacerbated climate harms, and other environmental injury such as noise and light pollution. In order to obtain a preliminary injunction, "a plaintiff must *demonstrate* immediate threatened injury as a prerequisite to preliminary injunctive relief." *Boardman v. Pac. Seafood Grp.*, 822 F.3d 1011, 1022 (9th Cir. 2016) (emphasis in original). The Ninth Circuit recognizes the "well-established public interest in preserving nature and avoiding irreparable environmental injury." *Cottrell*, 632 F.3d at 1138 (internal quotation marks and citation omitted). "While . . . it would be incorrect to hold that all potential environmental injury warrants an injunction, . . . [t]he Supreme Court has instructed us that [e]nvironmental injury, by its nature, can seldom be adequately remedied by money damages and is often permanent or at least of long duration, i.e., irreparable." *League of Wilderness Defenders/Blue Mountains Biodiversity Project v. Connaughton*, 752 F.3d 755, 764 (9th Cir. 2014) (citing *Lands Council v. McNair*, 537 F.3d 981, 1004 (9th Cir.2008) (en banc)).

In *League of Wilderness Defenders*, for example, the Ninth Circuit found that "the logging of thousands of mature trees" was a likely, irreparable harm that "c[ould not] be remedied easily if at all" by the "planting of new seedlings nor the paying of money damages." 537 F.3d at 764. On the other hand, in *Idaho Rivers United v. U.S. Army Corps of Eng'rs*, 156 F. Supp. 3d 1252, 1261–62 (W.D. Wash. 2015), the district court concluded that plaintiffs' assertion that "likely *potential* impacts and harm to Pacific lamprey *can* result from disturbance from dredge activities" fell short of demonstrating the requisite likely irreparable harm sufficient for the court to issue a preliminary injunction.

While Plaintiffs' assertions do not involve logging or damage to wildlife habitats, they do involve other concrete harms that BLM's own data suggests are significant and imminent. BLM estimates that the Suspension Rule *will* result in emissions of 175,000 additional tons of methane, 250,000 additional tons of volatile organic compounds, and 1,860 additional tons of hazardous air pollutants over the course of the year. 82 Fed. Reg. at 58,056–57. These numbers support Plaintiffs' concerns that the additional emissions will cause irreparable public health and environmental harm to Plaintiffs' members who live and work on or near public and tribal lands with oil and gas development. BLM characterizes the methane emissions, for example, as "infinitesimal," or "roughly 0.61 percent of the total U.S. methane emissions in 2015." Opp. at 12. But Plaintiffs submit affidavits from scientists who posit otherwise. Dr. Ilissa B. Ocko, climate scientist, states that the 175,000 additional tons of methane that will result during the one-year suspension is "equivalent to the 20-year climate impact of over 3,000,000 passenger vehicles driving for one year or over 16 billion pounds of coal burned." *See* App'x to Sierra Club Mot. at 499 ¶ 11. Dr. Renee McVay, whose research focuses on atmospheric chemistry, estimates that approximately 6,182 wells subject to the Waste Prevention Rule are located in counties already suffering from unhealthy air with elevated ozone levels. *See id*. at 786 ¶ 19. The Suspension Rule will result in additional emissions of 2,089 tons of VOCs in these already at-risk communities, where many of the conservation and tribal group plaintiffs' members reside, leading to and exacerbating impaired lung functioning, serious cardiovascular and pulmonary problems, and cancer and neurological damage. *See id*.; Sierra Club Mot. at 21.

Plaintiffs also provide several sworn affidavits from their individual members, attesting to the imminent and particularized harms from which they do and will suffer as a result of the Suspension Rule. Environmental Defense Fund member Francis Don Schreiber, for example, resides on a ranch in Governador, New Mexico, where there are 122 oil and gas wells either on or immediately adjacent to his land, all managed by BLM and subject to the Suspension Rule. *See* App'x to Sierra Club Mot. at 476–77. He notices an "extremely strong" "near-constant smell from leaking wells," which "make[s] breathing uncomfortable" and causes concern that he and his wife "are breathing harmful hydrocarbons." *Id*. at 479. As Schreiber suffers from a heart condition and has already had open heart surgery, he is "at a higher risk from breathing ozone," and is "constantly concerned about the impact of the air quality on [his] heart condition." *Id*. at 480. Plaintiffs provide similar affidavits from several other members. *See, e.g.*, *id*. at 510–16, 532–36, 562–64, 569–72, 627–31, 653–55, 717–22.

Nor does BLM dispute Plaintiffs' assertion that once such pollutants are emitted, they cannot be removed. The State of California, for example, asserts that once methane is released into the atmosphere, it contributes to irreparable harms, including a reduction in average annual snowpack (and therefore water supply), increased erosion and flooding from rising sea levels, as well as extreme weather events. *See* Cal. Mot. at 23. The State of New Mexico faces increased instances of water and electricity supply disruptions, drought, insect outbreak, and wildfire. *Id*. at 24. These are serious and irreparable harms that are directly linked to methane emissions.

Moreover, contrary to BLM's contention that increased air pollution is "incremental in nature" and does not require immediate relief, several courts, including the Supreme Court, have found that increased air pollution can constitute irreparable harm. *See, e.g.*, *Beame v. Friends of the Earth*, 434 U.S. 1310, 1314 (1977) (Marshall, J., in chambers) (recognizing "irreparable injury that air pollution may cause during [a two month] period, particularly for those with respiratory ailments); *Sierra Club v. U.S. Dep't of Agriculture, Rural Utils. Serv.*, 841 F. Supp. 2d 349, 358 (D.C. Cir. 2012) (concluding that plaintiff demonstrated irreparable harm where coal plant expansion would "emit substantial quantities of air pollutants that endanger human health and the environment"). Similar to *Sierra Club v. U.S. Department of Agriculture*, Plaintiffs have provided

affidavits from climate scientists and researchers supporting their assertions that the exposure to air pollution resulting from the Suspension Rule will have irreparable consequences for public health. *Compare Sierra Club v. U.S. Dep't of Agriculture*, 841 F. Supp. 2d at 358–59, *with* Sierra Club Mot. at 20–22. Plaintiffs have also offered affidavits from individual members showing concrete and particularized harms to respiratory health. *See Beame*, 434 U.S. at 1314. These affidavits are acceptable and sufficient to establish the requisite irreparable harm.[7]

BLM argues that Plaintiffs nonetheless cannot show that any alleged harms are "imminent" because operators are not ready to comply and will be unable to do so immediately. The relationship between these two contentions is unclear. Whether or not operators are ready to comply does not negate the imminence of Plaintiffs' harms; that operators are not currently poised to comply with the Waste Prevention Rule suggests that the harms to Plaintiffs from waste of natural gas and pollution would be even greater than estimated the longer that operators fail to comply. All the while, the wasted gas and emissions will continue to increase, leading to further irreparable harm.

Plaintiffs list several environmental injuries with effects statewide, to the general public, and on the personal level, any of which might be sufficient to establish likely irreparable harm. Considered collectively, plaintiffs easily meet their burden. Defendants' attempts to diminish these harms as merely incremental is unsupported by science as well as case law. For these reasons, I conclude that Plaintiffs have sufficiently demonstrated irreparable harm.

C. Balance of Equities and Public Interest

Finally, Plaintiffs must show that "the balance of equities tips in his favor, and that an

[7] BLM cites *Asarco, Inc. v. EPA*, 606 F.2d 1153, 1160 (9th Cir. 1980), and other cases for the proposition that the Court may not consider the "extra-record declarations" submitted by Plaintiffs "in evaluating the 'correctness or wisdom' of BLM's decision." *See* Opp. at 14 n.10. BLM is correct that it would be improper to consider these affidavits for purposes of substantive evaluation of the Suspension Rule under the APA. *See Asarco*, 606 F.2d at 1160 ("The same cases make clear that judicial consideration of evidence relevant to the substantive merits of the agency action but not included in the administrative record raises fundamentally different concerns."). I do not consider these affidavits in my analysis of the merits of the Suspension Rule and the arbitrary and capricious inquiry, as it would be inappropriate to look beyond the administrative record in so doing. The separate question of irreparable harm, however, is not limited to the administrative record, *see Sierra Club v. U.S. Dep't of Agriculture*, 841 F. Supp. 2d at 358–59, and none of the cases BLM cites discuss irreparable harm.

injunction is in the public interest." *Winter*, 555 U.S. at 20. The court "must balance the competing claims of injury and must consider the effect on each party of the granting or withholding of the requested relief." *Id*. at 24. All parties contend that the public benefits of their desired outcome are significant and urge the Court to find in their favor.

Plaintiffs focus on the loss of valuable natural resources through wasted gas, reduced royalties to local, state, and tribal entities, increased air pollution, the serious environmental harm to the public, as well as noise and visual nuisance. Defendants, for their part, argue that the Suspension Rule conserves the resources of operators and the agency while BLM reconsiders the Waste Prevention Rule. BLM estimates these costs to be approximately $110 to $114 million (depending on discount rates to annualize capital costs). *See* Opp. at 15. BLM also estimates that the initial upfront unrecoverable costs in 2018 would be $91 million. *Id*. They argue that "savings in compliance costs as compared to the monetized value of the increase in emissions and reduced captured gas results in a net benefit of $64–68 million, or $83–86 million depending on the discount rate used, during the suspension year." *Id*. at 15–16.

As previously discussed, these calculations are flawed because BLM assumes that compliance costs would never be incurred by industry, which is inconsistent with the Suspension Rule. Because it purports to merely suspend or delay compliance with the Waste Prevention Rule by only one year, those compliance costs are not saved, merely delayed. Even if I were to take these costs into consideration, placing these figures in context helps to understand their impact. Plaintiffs note that the average impact on individual businesses is insignificant; as previously discussed, even small operators will see an expected increase in profits of only 0.17%, a marginal amount, as a result of the Suspension Rule. Weighed against the likely environmental injury, which cannot be undone, the financial costs of compliance are not as significant as the increased gas emissions, public health harms, and pollution. *See, e.g*., *Mexichem Specialty Resins, Inc. v. E.P.A*., 787 F.3d 544, 555 (D.C. Cir. 2015) ("[I]t is well settled that economic loss does not, in and of itself, constitute irreparable harm.") (internal quotation marks and citation omitted); *accord Los Angeles Memorial Coliseum Comm'n v. Nat'l Football League*, 634 F.2d 1197, 1204 (9th Cir. 1980) (concluding that where plaintiff "has not shown that it will suffer any injury apart from

economic injury," its "injury is, therefore, not irreparable") (Wallace, J., concurring). Plaintiffs have demonstrated that these harms will have substantial detrimental effects on public health, and unlike economic loss, cannot be recovered. Thus, balancing the equities and considering both sides' impacts and costs, as well as the public interest, I conclude that the balance weighs in favor of granting the preliminary injunction.

Plaintiffs have provided several reasons that the Suspension Rule is arbitrary and capricious, both for substantive reasons, as a result of the lack of a reasoned analysis, and procedural ones, due to the lack of meaningful notice and comment. They have demonstrated irreparable harm and that the balance of equities and public interest strongly favor issuing the preliminary injunction sought. Because I conclude that they have met their burden on each element, I GRANT Plaintiffs' preliminary injunction enjoining enforcement of the Suspension Rule.

CONCLUSION

For the foregoing reasons, Defendants' motion to transfer venue to the District of Wyoming is denied. Plaintiffs' motion for a preliminary injunction is GRANTED.

IT IS SO ORDERED.

Dated: February 22, 2018

William H. Orrick
United States District Judge

Regulatory Impact Analysis for the Final Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule

U.S. Bureau of Land Management

August 31, 2018

Contents

1. Introduction

On November 18, 2016, the Bureau of Land Management (BLM) published a final rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" (2016 rule). The 2016 rule became effective on January 17, 2017, but with many of its provisions being phased in over time, beginning January 17, 2018.[1]

On March 28, 2017, the President issued E.O. 13783, entitled, "Promoting Energy Independence and Economic Growth." Section 7(b) of E.O. 13783 directs the Secretary of the Interior to review four specific rules, including the 2016 rule, for "consistency with the policy set forth in section 1 of [the] order and, if appropriate…publish for notice and comment proposed rules suspending, revising, or rescinding those rules."

As directed by the Executive Order, and by Secretarial Order No. 3349, "American Energy Independence," the BLM reviewed the 2016 rule. As a result of that review, the BLM published a proposed rule entitled "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Delay and Suspension of Certain Requirements." 82 FR 46458 (Oct. 5, 2017). After a public comment period, the BLM finalized that rule on December 8, 2017, thereby suspending or delaying the implementation of certain requirements of the 2016 rule until January 17, 2019 (2017 Suspension Rule). 82 FR 58050 (Dec. 8, 2017). The purpose of the 2017 Suspension Rule was to avoid imposing compliance costs on operators for requirements that may be rescinded or significantly revised in the near future. Subsequently, the U.S. District Court for the Northern District of California enjoined the Suspension Rule. *State v. Bureau of Land Management*, 286 F. Supp. 3d 1054 (N.D. Cal. 2018). However, following that injunction, the U.S. District Court for the District of Wyoming issued an order staying implementation of the "phase-in" provisions of the 2016 rule, which comprised the vast majority of the provisions affected by the 2017 Suspension Rule. *Wyoming v. U.S. Dep't of the Interior*, 2:16-CV-0285-SWS (D. Wyo.) (April 4, 2018).

On February 22, 2018, the BLM proposed a rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements" 83 FR 7924 (Feb. 22, 2018). The public comment period on that proposed rule closed on April 23, 2018. This Regulatory Impact Analysis (RIA) analyzes the impacts of the 2018 final rule to revise or rescind certain requirements of the 2016 rule. In general, this rule revises the 2016 rule in a manner that reduces unnecessary compliance burdens and, in large part, re-establishes and strengthens the long-standing requirements that the 2016 rule replaced. Notable improvements on NTL-4A in this final rule include: codifying a general requirement that operators flare, rather than vent, gas that is not captured (§ 3179.6); requiring persons conducting manual well purging to remain onsite in order to end the venting event as soon as practical (§ 3179.104); and, providing clarity about what does and does not constitute an "emergency" for the purposes of royalty assessment (§ 3179.103).

[1] The phased-in requirements pertained to gas-capture percentages (§ 3179.7), pneumatic equipment (§§ 3179.201-.202), storage vessels (§ 3179.203), and leak detection and repair (§§ 3179.301-.305).

BLM's Final Rule

The 2016 rule replaced the BLM's existing policy, Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A). The 2016 rule was intended to: Reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian (other than Osage Tribe) leases; clarify when produced gas lost through venting, flaring, or leaks is subject to royalties; and clarify when oil and gas production may be used royalty-free on-site. The final rule analyzed in this RIA replaces the requirements contained in the 2016 rule with requirements similar to those of NTL-4A.

The following requirements of the 2016 rule are removed in their entirety:

- Waste Minimization Plans (§ 3162.3-1);
- Well drilling requirements (§ 3179.101);
- Well completion and related operations requirements (§ 3179.102);
- Pneumatic controllers equipment requirements (§ 3179.201);
- Pneumatic diaphragm pumps equipment requirements (§ 3179.202);
- Storage vessels equipment requirements (§ 3179.203); and
- Leak Detection and Repair (LDAR) requirements (§ 3179.301-305).

The following requirements of the 2016 rule are modified and/or replaced with requirements that are similar to those that were in NTL-4A:

- Gas-capture requirement (§ 3179.7);
- Downhole well maintenance and liquids unloading requirements; and
- Measuring and reporting volumes of gas vented and flared.

The remaining requirements in the 2016 rule are retained, modified only slightly, or removed, but the impact of the removal would be small relative to the items listed previously.

Summary of Impacts

The Office of Management and Budget's (OMB) Office of Information and Regulatory Affairs (OIRA) reviewed the BLM's proposal to replace the 2016 rule and determined that this final rule is economically significant. This RIA draws heavily upon the analysis conducted in the RIA for the 2016 rule (2016 RIA).[2] This final rule is primarily expected to reverse the impacts previously estimated for the 2016 rule.

We estimate that this final rule will result in a reduction in compliance costs, forgone cost savings, forgone emissions reductions, and positive net benefits. Activities that would have been required to comply with the 2016 rule are no longer required. Relative to the baseline scenario in which the 2016 rule remains in effect, the BLM estimates that the 2018 final rule, over the 10-year evaluation period (2019-2028), will result in total net benefits ranging from \$734 million – \$1.009 billion (net present value (NPV) and interim domestic Social Cost of Methane (SC-CH_4)

[2] U.S. Bureau of Land Management, Regulatory Impact Analysis for: Revisions to 43 CFR 3100 (Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and Gas Operations); Additions of 43 CFR 3178 (Royalty-Free Use of Lease Production) and 43 CFR 3179 (Waste Prevention and Resource Conservation) (Nov. 10, 2016).

using a 7% discount rate) or $720 million – $1.083 billion (NPV and interim domestic SC-CH_4 using a 3% discount rate). The net benefits are $104 million – $144 million per year (annualized using a 7% discount rate) or $84 million – $127 million per year (annualized using a 3% discount rate).

Replacing the 2016 rule with requirements similar to those that were in force prior to that rule will not adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.

Additionally, while the BLM expects the 2018 final rule will reduce producers' compliance burdens and have a positive economic impact on small entities, the BLM has determined that this impact will not be "significant" for the purposes of the Regulatory Flexibility Act. The BLM based this determination on a review of the estimated change in the profit margins among a sample of small entities.

Finally, we estimate total forgone royalty payments, over a 10-year period (2019-2028), of about $28.3 million (NPV using a 7% discount rate) or $79.1 million (NPV using a 3% discount rate). The estimated forgone royalty payments are $4.03 million per year (annualized using a 7% discount rate) or $9.27 million per year (annualized using a 3% discount rate). (Of note, the BLM's estimate of forgone royalties is lower than the corresponding estimate of additional royalties that was initially estimated for the 2016 rule. This is due to a number of factors (see Section 4.5.2).) These estimates may not fully account for the potential that the reduced compliance burdens on industry might stimulate additional activity on Federal and Indian lands, resulting in additional production and royalties. The forgone royalty estimates may be overstated if certain assumptions made in the 2016 RIA understate the impact on production resulting from factors such as: (1) premature abandonment of marginal wells; (2) reservoir damage from wells temporarily shut-in; and (3) a shift in drilling activity to non-Federal lands. The forgone royalty estimates may be understated to the extent that the 2016 RIA assumptions overestimates these effects.

Table 1: Summary of Estimated Impacts; Final 2018 Rule, 2019 - 2028 ($ in million, 2016)

	Net Present Value (7%)	Net Present Value (3%)	Annualized (7%)	Annualized (3%)
Benefit: Estimated Reductions in Compliance Costs	$1,359 – 1,634	$1,712 – 2,076	$194 – 233	$201 – 243
Cost: Estimated Reductions in Natural Gas Recovery	$559	$734	$80	$86
Cost: Estimated Value of Forgone Emissions (domestic value of foregone CH_4 emissions)	$66	$259	$9	$30
Estimated Net Benefits (benefits - costs)	$734 – 1,009	$720 – 1,083	$104 – 144	$84 – 127

*Totals may not sum due to rounding.

2. Background

2.1 Requirements for Economic Analysis

By statute and executive order, an agency undertaking a significant regulatory action is required to provide a qualitative and quantitative assessment of the anticipated costs and benefits of that action.

E.O. 12866, "Regulatory Planning and Review," requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to OMB for review. A rule may be significant under E.O. 12866 if it meets any of the following four criteria. A significant regulatory action is any rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The purpose of this economic analysis is to provide information allowing decision makers to determine that:

- There is adequate information indicating the need for and the consequences of this action;
- The potential benefits to society justify the potential costs, recognizing that not all benefits and costs can be described in monetary or even in quantitative terms, unless a statute requires another regulatory approach;
- This action will maximize net benefits to society (including potential economic, environmental, public health and safety, and other advantages; distributional impacts; and equity), unless a statute requires another regulatory approach;
- Where a statute requires a specific regulatory approach, this action will be the most cost-effective, including reliance on performance objectives to the extent feasible; and
- Agency decisions are based on the best reasonably obtainable scientific, technical, economic, and other information.

To provide this information, per OMB Circular A-4, the economic analyses of economically significant rules will contain three elements:

- A statement of the need for the proposed action;
- An examination of alternative approaches; and
- An analysis of benefits and costs.

The Regulatory Flexibility Act (RFA) and the Small Business Regulatory Enforcement Fairness Act (SBREFA) require agencies to analyze the economic impact of regulations to determine whether there would be a significant economic impact on a substantial number of small entities.

If a rule will have a significant economic impact on a substantial number of small entities when it is promulgated, then agencies must conduct an initial regulatory flexibility analysis with the proposed rule and a final regulatory flexibility analysis with the final rule.[3] If the rule will not have a significant economic impact on a substantial number of small entities when it is promulgated, then agencies do not have to conduct the initial or final regulatory flexibility analysis.[4]

Federal law also requires special considerations if OIRA determines that the rule is "major."[5] A rule is major if it has resulted in or is likely to result in:

- An annual effect on the economy of $100 million or more;
- A major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or
- Significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.

If OIRA determines that a rule is major, then the rule may become effective 60 days after the agency promulgates it and submits it to Congress. A major rule is subject to congressional review and other procedural requirements.[6]

E.O. 13272 reinforces executive intent that agencies give serious attention to impacts on small entities and develop regulatory alternatives to reduce the regulatory burden on small entities. When the regulation will impose a significant economic impact on a substantial number of small entities, the agency must evaluate alternatives that would accomplish the objectives of the rule without unduly burdening small entities.

2.2 Need for Policy Action

On March 28, 2017, the President issued E.O. 13783, "Promoting Energy Independence and Economic Growth." Section 7(b) of that order directs the Secretary of the Interior to review four specific rules, including the 2016 rule, for "consistency with the policy set forth in section 1 of [the] order and, if appropriate . . . publish for notice and comment proposed rules suspending, revising, or rescinding those rules."

The policy set forth in Section 1 of E.O. 13783 is that "it is in the national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time

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[3] 5 U.S.C. 603 and 5 U.S.C. 604.

[4] 5 U.S.C. 605.

[5] 5 U.S.C. 804.

[6] 5 U.S.C. 801.

avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation" (Section 1 (a)). Further, "it is also the policy of the United States that necessary and appropriate environmental regulations comply with the law, are of greater benefit than cost, when permissible, achieve environmental improvements for the American people, and are developed through transparent processes that employ the best available peer-reviewed science and economics" (Section 1 (e)).

As shown in Table 2.2, we estimate that the 2016 rule requirements would have imposed a net cost (i.e., negative net benefit) of $736 million – $1.011 billion (NPV using a 7% discount rate) or $722 million – $1.086 billion (NPV using a 3% discount rate) over 10 years from 2019 – 2028.[7]

The conclusion that the final 2016 rule would impose net costs differs from the results contained in the RIA for the 2016 rule. The net negative benefit result is primarily due to the use of a domestic Social Cost of Methane (SC-CH_4), as opposed to the global values for SC-CH_4 that were used in the RIA for the 2016 rule. The rationale for this change is explained in Section 3.3 of this RIA and in the Appendix. Another contributing factor to the net-cost result is that the gas-capture target provisions would be implemented immediately. In the RIA for the 2016 rule, the costs of those requirements were delayed to reflect the one-year phase-in period. The difference in the benefit and cost estimates from what was estimated in the final 2016 rule is shown in Section 7.4.

Table 2.2: Compliance Costs, Cost Savings, Value of Methane Emissions Reductions, and Net Benefits, Re-estimated for the 2016 Rule, 2019 – 2028 ($ in millions)

	Net Present Value (7%)	Net Present Value (3%)	Annualized (7%)	Annualized (3%)
Compliance costs (Cost)	$1,362 – 1,637	$1,715 – 2,079	$194 – 233	$201 – 244
Cost savings (Benefit)	$559	734	$80	$86
Value of methane reductions (Benefit)	$66	$259	$9	$30
Net Benefits	($736 – 1,011)	($722 – 1,086)	($105 – 144)	($85 – 127)

* Discounting done relative to 2018

As directed by E.O. 13783 and by Secretarial Order 3349, the BLM reviewed the 2016 rule and determined that many requirements were inconsistent with the policy set forth in Section 1 of E.O. 13783. In addition to imposing net costs, the 2016 rule has requirements that are duplicative of other Federal and State regulations and would have imposed compliance burdens that could unnecessarily constrain the development of the Nation's energy resources.

[7] We estimate that the NPV gross compliance costs associated with the 2016 rule requirements (excluding the sales from recovered gas) would be $1.31–1.58 billion (NPV using a 7% discount rate) or $1.65–2.01 billion (NPV using a 3% discount rate) over 10 years from 2019–2028. The estimated compliance costs are about $62,400 per operator per year.

2.3 2018 Final Rule Requirements and Discussion

The following table provides a section-by-section analysis of the 2018 final rule's provisions and their significance.

Table 2.3a: 2016 Rule Provisions Being Removed

2016 rule Citation	Summary	Significance of Change
§ 3162.3-1(j)	Operators must submit a waste minimization plan with an Application for Permit to Drill (APD).	This provision is removed and the operator is no longer required to submit a waste minimization plan. The change reduces the regulatory burden associated with submitting this additional information with an APD.
§ 3179.7	Operators are required to capture a certain amount of produced gas, after allowing for a certain volume of flaring per well. The capture percentage would increase in future years and the amount of flaring allowed would decrease.	This provision is removed and the operator is no longer subject to the flaring limitations and framework of this section of the 2016 rule. Instead, the operator is subject to the new oil-well gas flaring provisions (described in the Table 2.3b). The change is expected to substantially reduce compliance burdens but result in forgone gas recovery.
§ 3179.8	Allows operators of leases issued before January 17, 2017, to request a lower gas-capture percentage if complying with § 3179.7 would cause the operator to "cease production and abandon significant recoverable oil reserves under the lease."	This provision is no longer relevant since § 3179.7 is removed.
§ 3179.11	States that the BLM may exercise its existing authority to limit production from a new well that is expected to force other wells off of a common pipeline, delay action on an APD, or impose conditions of approval on an APD.	This section is removed, but the BLM's authority to take these actions remains (under applicable laws and regulations, as well as under the terms of applicable permits, orders, leases, and unitization or communitization agreements). Section 3179.11 was not an independent source of authority or obligation on the part of the BLM.
§ 3179.12	States that, to the extent an action to enforce 43 CFR subpart 3179 may adversely affect production of oil or gas from non-Federal and non-Indian mineral interests, the BLM will coordinate with the appropriate State regulatory authority.	This section is removed and there would be little practical impact if any. The BLM has revised subpart 3179 in a manner that defers to State and tribal requirements with respect to the routine flaring of associated gas.
§ 3179.101	Limits on, and requirements for disposal of, gas lost during well drilling. Exceptions allowed when flaring is technically infeasible.	This provision is removed and the operator is no longer required to capture, re-inject, use in the operations, or flare gas coming to the surface during well drilling. The change is not expected to have a

2016 rule Citation	Summary	Significance of Change
		substantial impact on operations, as operators control and combust gas during well drilling for safety reasons and as part of standard practice.
§ 3179.102	Limits on, and requirements for disposal of, gas lost during well completion and related operations. Exemptions allowed if compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.	This provision is removed and the operator is no longer required to capture, re-inject, use in operations, or flare gas resulting during well completion and related operations. The change is not expected to have a substantial impact on operations, as the EPA's NSPS at 40 CFR part 60 subparts OOOO and OOOOa regulate well-completion operations on hydraulically fractured natural gas and oil wells.
§ 3179.201	Operators must replace high-bleed pneumatic controllers with low-bleed controllers. Exemptions if the controllers are covered by EPA regulations or if existing facilities have less than 3 years of remaining life or if compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.	This provision is removed and the operator is no longer required to replace or modify existing controllers not already in compliance with the 2016 rule. The change will reduce compliance costs for operators with facilities that have existing continuous high-bleed pneumatic controllers. Low-bleed controllers are common in the industry as many operators are pursuing more efficient production equipment on a voluntary basis. Low-bleed pneumatic controllers reportedly make up 88% of the total continuous pneumatic controllers while high-bleed controllers make up 12% of the total.[8] The change is also expected to result in forgone gas recovery and emissions reductions.
§ 3179.202	Operators must replace pneumatic diaphragm pumps with a zero-emissions pump or route the gas to processing equipment for capture and sale. Exemptions if the controllers are covered by EPA regulations. The operator may route to a flare or combustion device under certain circumstances. Exemptions allowed if compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.	This provision is removed and the operator is no longer required to replace or modify existing pumps not already in compliance with the 2016 rule. The change will reduce compliance costs for operators with facilities that are not already in compliance but result in forgone gas recovery and emissions reductions.
§ 3179.203	If potential emissions from a storage vessel exceed 6 tons per year, the operator must route vapors to sales line unless infeasible or unduly costly; otherwise	This requirement is removed and the operator is no longer required to modify storage vessels and/or add combustors to facilities not already in compliance with the 2016 rule. The change will reduce compliance

[8] According to data available in the EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2016. See Annex 3 Methodological Descriptions for Additional Source or Sink Categories at Table 3.5-5: Activity Data for Petroleum Systems Sources, for All Years and Table 3.6-7: Activity Data for Natural Gas Systems Sources, for All Years.

2016 rule Citation	Summary	Significance of Change
	route to combustion device. Exemptions if the storage vessels are covered by EPA regulations. Exemptions allowed if compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.	costs for operators with facilities that are not already in compliance but result in relatively small amounts of forgone gas recovery and emissions reductions. In the RIA, the BLM estimates that relatively few facilities will actually be affected. The EPA's regulations have covered storage vessels since 2012. Given production declines, we expect that fewer facilities would exceed the VOC threshold over time, and so the number of facilities that will be affected by the 2016 rule should decline over time.
§§ 3179.301 – 3179.305	These sections establish LDAR requirements on all wellsites and compressors located on Federal and Indian leases. The inspection requirements are semi-annual for wellsites and quarterly for compressors. Exemptions if the facility is covered by EPA regulations or if compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease. There are various compliance dates depending on the facility.	This requirement is removed and the operator is not required to conduct LDAR by the BLM. This change will reduce compliance burdens for operators of all wellsites that are not already covered by the EPA's regulations but result in forgone gas recovery and emissions reductions.

Table 2.3b: 2018 Final Rule Requirements

Rule Citation	Summary	Significance of Change
§ 3179.1	Purpose. This section states that the purpose of this subpart is to implement and carry out the purposes of statutes relating to prevention of waste from Federal and Indian leases, the conservation of surface resources, and management of the public lands for multiple use and sustained yield.	No change.
§ 3179.2	Scope. This section specifies which leases, agreements, tracts, facilities, and gas lines are covered by this subpart. The section also states that the term "lease" in this subpart includes Indian Mineral Development Act agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement.	The final rule makes one minor revision to paragraph (a)(5) by using the more-inclusive words "well facilities" instead of the words "wells, tanks, compressors, and other equipment" to describe the onshore equipment that are subject to this final rule. The change reflects the removal of the LDAR provisions. There will be no substantive or measureable impact from the change to this section.
§ 3179.3	Definitions and acronyms. This section provides the definitions and acronyms relevant for the subpart.	The final rule removes definitions that are no longer necessary and adds some new definitions. There will be no substantive or measureable impact from the change to this section.
§ 3179.4	Determining when the loss of oil or gas is avoidable or unavoidable. This section describes the circumstances under which lost oil or gas will be classified as "avoidably lost" or "unavoidably lost." The proposed revision incorporates concepts that appear in both existing § 3179.4 and NTL-4A, Sections II and III.	Although there are some alterations to the previous (2016 rule) section, the changes are conforming changes that reflect the modifications made to other portions of the subpart. There will be no substantive or measureable impact from the proposed change to this section.
§ 3179.5	When lost production is subject to royalty. This section explains that avoidably lost oil and gas is royalty bearing and unavoidably lost oil and gas is not royalty bearing.	This section of the final rule is the same as the previous section.
§ 3179.6	Venting limitations. Prohibits gas flaring and venting from gas wells, with certain exceptions, and requires operators to flare, rather than vent, any uncaptured gas from all wells, with certain exceptions.	The title of this section in this final rule has been changed from "venting prohibitions" to "venting limitations." The final rule retains most of the provisions in existing § 3179.6. There will be no substantive or measureable impact from the change to this section.

Rule Citation	Summary	Significance of Change
§ 3179.101	Authorized flaring and venting of gas – Initial production testing. The 2018 rule establishes volume and duration standards which limit the amount of gas that may be flared royalty free during initial production testing. The gas is no longer royalty free after reaching either limit. The final rule establishes a volume limit of 50 MMcf (million cubic feet) of gas that may be flared royalty free during the initial production test of each completed interval in a well. Additionally, the final rule limits royalty-free initial production testing to a 30-day period, unless the BLM approves a longer period.	The 2018 final rule revises the volume limit of 20 MMcf for royalty-free flaring during initial production testing. This final rule and the 2016 rule are quite similar in addressing the royalty-free treatment of gas volumes flared during initial production testing. The primary difference between the two rules is that under the 2016 rule the operator must request approval from the BLM to flare royalty free the same volume of gas, or for the same duration, that is allowed under the 2018 final rule. While the compliance burden should be reduced under the proposed rule, the actual impact depends on the how the 2016 rule would have been enforced over time.
§ 3179.102	Authorized flaring and venting of gas – Subsequent well tests. This final rule provides that gas flared during well tests subsequent to the initial production test is royalty free for a period not to exceed 24 hours unless the BLM approves or requires a longer test period. The operator must request a longer test period using a Sundry Notice.	The final rule is functionally identical to the 2016 rule.
§ 3179.103	Authorized flaring and venting of gas – Emergencies. Royalty is not due on gas that is lost during an emergency under the final rule. The final rule describes the conditions that constitute an emergency, and lists circumstances that do not constitute an emergency. The final rule requires the operator to report to the BLM the volumes of gas that were flared or vented beyond the timeframe of the emergency, e.g. up to 24 hours or a longer period determined necessary by the BLM.	The emergency provisions in the 2016 rule are nearly identical to those of this final rule. The most notable change from the 2016 rule to the 2018 final rule is in describing those things that do not constitute an emergency. Where the 2016 rule specified that “more than 3 failures of the same component within a single piece of equipment within any 365-day period” was not an emergency, the 2018 final rule simplifies that concept to provide that “recurring equipment failures” do not constitute an emergency. The revision also clears up one incorrect reference that appeared in the 2016 rule. Overall, the changes described are not expected to result in a substantive or measureable impact.
§ 3179.104	Authorized flaring and venting of gas – Downhole well maintenance and liquids unloading. The final rule allows an operator to unload liquids from the wellbore by purging the well for a period of up to 24 hours. Gas that is lost during a manual well purging	The final rule retains some of the same concepts and provisions as the 2016 rule. The main difference is that the 2016 rule placed additional operational and administrative requirements on the operator that the 2018 final rule removes. Specifically, the 2016 rule required the operator to file a Sundry Notice with the BLM the first time that each

Rule Citation	Summary	Significance of Change
	event is royalty free if the person conducting the purging remains present on-site throughout the event in order to end the event as soon as practical thereby minimizing the volume of gas lost. Gas that is flared or vented from a plunger lift system or automated control system is royalty free provided that the system is optimized to remove liquids from the wellbore while venting or flaring as small a volume of gas as is practical.	well is manually purged or purged with an automated control system. In that notice, the operator must have evaluated the feasibility of using methods of liquids unloading other than well purging and that the operator determined that such methods were either unduly costly or technically infeasible. The final rule removes these operational and administrative burdens. In the RIA for the 2016 rule, we estimated that the requirements would result in additional lift systems being installed. While it is still possible that operators will make these investments voluntarily (plunger lift systems are very common), it is not certain. As a result, there will likely be fewer gas volumes recovered from new installations.
§ 3179.201	Other venting or flaring – Oil well gas. The final rule allows operators to vent or flare oil-well gas royalty free in compliance with governing rules, regulations, or orders of the State regulatory agency or tribe in which the venting or flaring of oil-well gas occurs. The final rule provides general guidelines for what applicable rules, regulations, or orders, should contain, in terms of placing recognizable limitations on the venting and flaring of oil-well gas. In the absence of State regulations for Federal lands and tribal regulations for tribal lands, this section requires a case-by-case approval of flaring, similar to that employed under NTL-4A.	This section replaces the Gas-Capture Requirement (described in Table 2.3b). The final rule replaces the complex framework established in the 2016 rule with a simplified version using NTL-4A. In the RIA for the 2016 rule, the BLM estimated that there would be a certain amount of crude oil production deferred to the future and a certain amount of additional natural gas produced that would have otherwise been flared. This final rule reverse those impacts. This final rule defers to State regulations for Federal wells and tribal regulations for tribal wells, reducing the administrative burden – for both operators and BLM – associated with applications to flare under NTL-4A.
§ 3179.301	Measurement and reporting responsibilities – Measuring and reporting volumes of gas vented and flared. The final rule requires operators to estimate (using estimation protocols) or measure (using a metering device) all flared and vented gas, whether royalty bearing or royalty free, and report the volumes under applicable Office of Natural Resources Revenue (ONRR) reporting requirements.	This final rule is generally consistent with NTL-4A. The main difference between the final rule and the 2016 rule is that it removes the requirement to measure flared gas above 50 Mcf per day. As such, this final rule will alleviate the compliance burden of operators having to install flare meters in certain circumstances.

Rule Citation	Summary	Significance of Change
§ 3179.401	Deference to Tribal Regulations. The final rule allows for Tribes with rules, regulations, or orders that are applicable to any of the matters addressed in subpart 3179 to seek approval from the BLM to have such rules, regulations, or orders apply in place of any or all of the provisions of subpart 3179. The BLM will approve a Tribe's request to the extent that it is consistent with the BLM's trust responsibility.	This section in the final rule is supplemental to, and does not limit, the deference to Tribal rules, regulations, or orders provided for in § 3179.201. This section is likely to encourage Tribes to develop comprehensive rules, regulations, or orders concerning additional aspects of subpart 3179.

2.4 Consideration of Alternative Approaches

In developing this final rule, the BLM considered several alternatives. In section 4 of this RIA, we present estimated impacts for the baseline, the final rule, and another alternative. However, the reader may also evaluate the impacts of the proposed changes to the major equipment and operational requirements of the 2016 rule individually, as estimates of those impacts are provided in section 4. That is, the reader may evaluate the rescinded requirements on their individual merit, and can therefore consider a number of scenarios in which different combinations of changes to the 2016 rule are (or are not) made.

As for the defined alternatives, we examine: (1) A "No Action" or "Baseline" scenario in which the BLM retains and implements all of the 2016 rule's requirements; (2) The 2018 final rule; and, (3) An alternative scenario (referred to as "Alternative 2" in Section 4) in which the BLM retains and implements the 2016 rule's gas-capture requirements (2016 rule §§ 3179.7 – 3179.8) and the associated measurement/metering requirements (2016 rule § 3179.9) while rescinding the operational and equipment requirements addressing vented volumes (i.e., the requirements for pneumatic equipment, storage tanks, liquids unloading, and LDAR).

2.5 Alternatives to Direct Regulation

E.O. 13563 reaffirms the principles of E.O. 12866 and requires that agencies, among other things, "identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public."

The 2016 rule established requirements and direct regulation on operators. The 2018 final rule removes those requirements of the 2016 rule that posed the most substantial direct regulatory costs on operators. Also, the 2018 final rule removes the duplicative operational and equipment requirements and paperwork and administrative burdens.

2.6 Background – Venting and Flaring from Oil and Gas Operations

The following section discusses some of the scenarios under which natural gas is vented or flared from oil and gas operations. The sources described below are the primary sources of vented and flared gas from oil and gas production operations, as identified by the Government Accountability Office (GAO) and other studies. The requirements of the BLM's 2016 rule were designed to limit the loss of gas from these sources. There are other regulatory requirements and legal restrictions that prevent the venting or flaring of gas from these sources, depending on the operation or its location. For example, the Environmental Protection Agency (EPA) regulates many of these sources on new, reconstructed, or modified wellsites or facilities and some States have regulations that place restrictions on venting or flaring.

A. Gas flaring from production operations, including associated gas

Associated gas (or casinghead gas) is the natural gas that is produced from an oil well during normal production operations and is either sold, re-injected, used for production purposes, vented (rarely), or flared, depending on whether the well is connected to a gathering line or other method of capture.

Production tests (or productivity tests) are "tests in an oil or gas well to determine its flow capacity at specific conditions of reservoir and flowing pressures. The absolute open flow potential (AOFP) can be obtained from these tests, and then the inflow performance relationship (IPR) can be generated."[9] The AOFP is "the calculated maximum flow rate that a system may provide in the absence of restrictions."[10] To determine an AOFP, the operator may need to flare gas (and sometimes vent) for a period of time; however, it is also possible to calculate the AOFP while capturing the gas in a sales line. For conventional oil and gas wells, well completions and production tests are separate processes temporally. For unconventional wells, however, operators may conduct production tests during flowback.

In addition, emergency flaring or venting may be necessary for safety reasons.

B. Well completions and workovers

Well completion is the process of transforming a drilled well into a producing well. Hydraulic fracturing is a type of well completion. Refracturing is "an operation to re-stimulate a well after an initial period of production,"[11] and is a hydraulic fracturing completion. A well workover is "cleaning" of the well that can also refer to "the repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons."[12]

Releases may occur during any well completion and workover; however, greater releases are associated with "flowback" from a hydraulic fracturing completion. Flowback is "the process of

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[9] "Productivity test" as defined by the Schlumberger Oilfield Glossary.

[10] "Open flow potential" as defined by the Schlumberger Oilfield Glossary.

[11] "Refracturing" as defined by the Schlumberger Oilfield Glossary.

[12] "Workover" as defined by the Schlumberger Oilfield Glossary, http://www.glossary.oilfield.slb.com/en/.aspx.

allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production."[13]

During flowback, an operator will generally return recovered fluids to a temporary 3-phase flowback separator. From the separator, the gas is either diverted to a sales line or is vented or flared, the flowback water is returned to a flowback tank (and then trucked or pumped out), and the hydrocarbon liquid is returned to a storage tank. If uncontrolled, natural gas releases may occur during any step of this process.

C. Pneumatic controllers

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure differential, and temperature. Depending on the design, controllers are most often used in the oil and gas industry to operate and control valves by use of readily available high-pressure natural gas.

In natural-gas-driven pneumatic controllers, natural gas is released with every actuation, or movement, of the valve. These controllers come in three basic designs for a variety of uses: continuous bleed controllers, intermittent controllers, and zero bleed controllers.

Continuous- bleed pneumatic controllers are those that release a continuous flow of pneumatic supply natural gas from the valve control pilot to the process control device. They are designed for a variety of uses, including level control, temperature control, and pressure control. Continuous controllers are generally classified by their bleed rate – the rate at which they continuously release gas. Low-bleed continuous controllers have a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh), while high-bleed continuous controllers have a bleed rate exceeding 6 scfh.

Intermittent pneumatic controllers are pneumatic controllers that vent non-continuously. These controllers are actuated using pressurized natural gas, but do not bleed continuously and can serve functionally different purposes than continuous-bleed controllers. These controllers release gas only when they open or close a valve or as they throttle the gas flow.

Zero-bleed pneumatic controllers do not bleed natural gas into the atmosphere. Rather, they are self-contained devices that release gas to a downstream pipeline instead of into the atmosphere.

Other controllers are limited by their functionality and feasibility. Non-natural gas-powered pneumatic controllers may be solar-powered, powered by electricity from the grid, or powered by instrument air and have secondary impacts related to generation of required electric power. Non-natural-gas-driven pneumatic controllers, such as instrument air devices, can be used depending on the application, but can be cost-prohibitive because they require electricity sufficient to power an air compressor. Mechanical controllers can replace continuous-bleed

[13] "Flowback" as defined by the Schlumberger Oilfield Glossary.

controllers and intermittent controllers in many applications, but likewise require electricity as their power source.

D. Pneumatic pumps

Pneumatic pumps are devices that use gas pressure to drive or compress liquids or gases by raising or reducing the pressure of the fluid by means of a positive displacement, a piston, or a set of rotating impellers, and they are generally used at oil and natural gas production sites where electricity is not readily available. The supply gas for these pumps is most often natural gas from the production stream, though they may also use compressed air. The gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.

The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation. The chemicals are typically injected at the wellhead and into gathering lines or at production separation facilities. During chemical injection, piston pumps or diaphragm pumps will inject small amounts of chemicals to limit processing problems and protect equipment. Pneumatic pumps are used for glycol circulation and recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.

E. Liquids unloading

In producing gas wells, fluids may accumulate in the wellbore and impede the flow of gas, sometimes halting production. Gas wells generally have sufficient pressure to produce both formation fluids and gas early on, but as production continues and reservoir pressure declines, the gas velocity in the production tubing may not be sufficient to lift the formation fluids. When this occurs, liquids (hydrocarbons and salinized water) may accumulate in the tubing, causing a further drop in pressure, slowed gas velocity, and raised pressure at the perforations. When the bottom-hole pressure becomes static, gas flow stops and all liquids accumulate at the bottom of the tubing.

When liquid accumulation occurs, there are a number of options available to operators to remove the liquids, including:[14]

- Installing an artificial lift system or other pumping unit;
- Installing smaller diameter tubing;
- Swabbing the well to remove the fluids;
- Using a surfactant to reduce the density of the fluid column; or
- Shutting-in the well to increase bottom-hole pressure and then venting the well to the atmosphere (well purging).

We note that venting may occur during all of these interventions. Generally, lift systems reduce the volume of venting and facilitate the capture and production of gas that would otherwise be

[14] An EPA document, *Lessons learned from natural gas STAR partners: Options for removing accumulated fluid and improving flow in gas wells*, describes the problem of liquid accumulation and options for removing the fluids.

vented during purging. However, certain plunger lifts may not be connected to a gas flow line and may vent some gas in the process of unloading.

Liquid accumulation may become a recurring problem depending on the intervention that an operator uses. Lift systems, pumping units, or smaller-diameter tubing, are longer-lasting solutions, while swabbing, surfactants, and well purging are only temporary solutions.

F. Oil and condensate storage tanks

Crude oil and condensate tanks or vessels are used on-site to store produced hydrocarbons and other fluids. In most cases, an operator will direct recovered fluids from the well to a separator, with the hydrocarbons then directed to the storage tanks.

During storage, light hydrocarbons dissolved in the crude oil or condensate vaporize and collect in the space between the tank liquids and the tank roof. These vapors are often vented to the atmosphere when the liquid level in the tank subsequently fluctuates. Losses of gas vapors generally occur when oil is dumped into the tank, the fluids within the tank are circulated or agitated, or when the temperature changes. Lighter crude oil, with API gravity greater than 36°, typically vaporizes more easily.

Rather than release these vapors to the atmosphere, an operator may install a combustion device to combust the vapors or it may install a vapor recovery unit (VRU) to capture gas vapors for sale. Capturing the gas with a VRU requires that a well be connected to a gas-gathering line. VRUs have been shown to reduce volatile organic compound (VOC) emissions from storage vessels by approximately 95 percent. Recovered vapors have a British Thermal Unit (Btu) content that is higher than pipeline quality natural gas. The vapors may range between 950 to 1,100 Btu per standard cubic foot (scf), and can reach as high as 2,000 Btu/scf.

G. Leaks

Production sites with the potential for natural gas leaks include natural-gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of leaks include seals, connectors, flanges, hatches, and valves, among others. Leaked gases, or evaporated liquids, are lost to the atmosphere. The leaked natural gas is lost production, and results in the release of methane, VOCs, and other air pollutants (including hazardous air pollutants such as benzene) into the air.

2.7 Estimated Venting and Flaring from Federal and Indian Leases

GAO Investigations

1. 2010 Report Containing Estimated Losses in 2008

In 2010, the GAO released a report entitled, *Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases.*[15] In this report, the GAO concluded that 126 Bcf of natural gas was vented and flared from onshore Federal leases in 2008. The sources of the lost gas accounting for that volume included: Flaring from a variety of sources (28 Bcf); pneumatic devices (16 Bcf); gas well liquids unloading (17 Bcf); well completions (30 Bcf); oil and condensate storage tanks (18 Bcf); glycol dehydrators (7 Bcf); and other (10 Bcf).[16]

The GAO further concluded that about 50 Bcf of that gas could be economically captured using currently available technology, including low-bleed pneumatic devices, smart automated plunger lifts, reduced-emissions completions, and vapor recovery devices.[17] It estimated that 40% of the gas was economically recoverable, representing $23 million in annual Federal royalties, and 16.5 million metric tons of CO_2 equivalent emissions.[18]

Table 2.7a: GAO Estimated Venting and Flaring from Federal Leases in 2008, Reduction Technologies, and Potential Reductions

Sources	Vented/ Flared Volume (Bcf)	Reduction Technology	Potential Reduction (Bcf)	Percent of Total Volume Vented/ Flared
Flared (variety of sources)	28			
Pneumatic devices	16	Use low bleed devices	9.7	7.7%
Gas well liquids unloading	17	Expanded use of smart automated plungers	7.2	5.7%
Well completions	30	Expanded use of reduced emissions completions	14.7	11.7%
Oil and condensate tanks	18	Install vapor recovery units	12.9	10.2%
Glycol dehydrators	7	Install vapor recovery devices	5.7	4.5%
Other	10			
Total	**126**		**50.2**	**39.8%**

Source: GAO 2010, pp. 12 and 20.

[15] GAO (2010). Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases (GAO-11-34). October 2010. Available at http://www.gao.gov/new.items/d1134.pdf.

[16] Ibid., p. 12.

[17] Ibid., p. 20.

[18] Ibid., highlights.

2. 2016 Report Concerning the Reporting of Emissions

In July 2016, the GAO issued a report entitled, *OIL AND GAS: Interior Could Do More to Account for and Manage Natural Gas Emissions.*[19] The GAO found that Interior's "guidance to oil and gas operators on its reporting requirements has limitations that may hinder the extent to which it can account for natural gas emissions on onshore federal lands (leases)."

The GAO concluded that, "as a result of these limitations, Interior may not have a consistent accounting of natural gas emissions from onshore federal leases, and does not have the information it needs to reasonably ensure it is minimizing waste on these leases, and that the BLM field offices have not consistently followed BLM's existing guidance in managing operators' venting or flaring requests."

The GAO recommended that the BLM provide additional guidance on how to estimate natural gas emissions from federal oil and gas leases to help improve reporting of emissions data on the ONRR's Oil and Gas Operations Report (OGOR). Operators are required to report production data and natural gas disposition to ONRR through OGOR forms.

Updated Estimates of Natural Gas Venting and Flaring from Federal and Indian Leases

The BLM reviewed the available data in an effort to update the estimates provided by the GAO in its 2010 report. The BLM relied on flaring data provided by ONRR and venting data available in the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2016 ("2018 GHG Inventory").

Based on this review, the BLM estimates that 89 Bcf of natural gas was vented or flared from Federal and Indian onshore leases in 2016. We note that this estimate is lower than our estimate of vented and flared gas from Federal and Indian leases in 2014 (see BLM's 2016 RIA at p. 16 and Table 2.7c below). For 2014, we had estimated that 111 Bcf of natural gas was vented or flared (81 Bcf flared and 30 Bcf vented) from Federal and Indian leases. See discussion that follows on the comparison of venting and flaring estimates.

Of the 89 Bcf estimated to be vented and flared in 2016, the BLM estimates that 68 Bcf was flared and 21 Bcf was vented. With respect to venting, pneumatic controllers represent the bulk of the natural gas losses with fugitive emissions (or leaks), liquids unloading, and storage tanks following. We present the estimated volumes of gas loss for each source and the relative share in the context of total venting/flaring and venting alone. The sources of natural-gas venting (and leaks) ranked by the percent of total vented volumes are: Pneumatic controllers (54.6%), fugitives (17.5%), liquids unloading (4.6%), storage tanks (4.2%), pneumatic pumps (7.9%), gas engines (5.9%), well completions and workovers (3.5%), and compressors (1.9%). See Table 2.7b for more detail.

[19] GAO (2016). OIL AND GAS: Interior could do more to account for and manage natural gas emissions (GAO-16-607). July 2016. Available at https://www.gao.gov/products/GAO-16-607.

Table 2.7b: Estimated Venting and Flaring from Federal and Indian Leases in 2016

Source[3]	Natural Gas Releases from Natural Gas Production Segment (Bcf)	Natural Gas Releases from Petroleum Production Segment (Bcf)	Vented/ Flared Total (Bcf)	Percent of Total Vented/ Flared	Percent of Total Vented
Flared Gas[1]	2.29	65.77	68.06	76.1%	NA
Well Completions and Workovers[2]	0.34	0.42	0.76	0.8%	3.5%
Pneumatic Controllers[2]	7.75	3.95	11.70	13.1%	54.6%
Pneumatic Pumps[2]	1.25	0.43	1.68	1.9%	7.9%
Gas Engines[2]	0.78	0.47	1.26	1.4%	5.9%
Compressors[2]	0.39	0.01	0.40	0.4%	1.9%
Liquids Unloading[2]	0.98	0.00	0.98	1.1%	4.6%
Storage Tanks[2]	0.22	0.68	0.90	1.0%	4.2%
Fugitives[2]	2.99	0.75	3.74	4.2%	17.5%
Total	**17.00**	**72.48**	**89.48**	**100.0%**	

1 Estimated from data reported by operators to ONRR's OGOR. Full discussion of methodology is below.

2 The EPA's national emissions estimates in the 2018 GHG Inventory were adjusted downward based on the share of U.S. natural gas production in 2016 that came from Federal and Indian lands (about 11.17%) and the share of U.S. crude production in 2016 that came from Federal and Indian lands (about 8.10%). Full discussion of methodology is below.

3 In addition to these source categories, the EPA GHG Inventory provides estimates for emissions coming from natural gas gathering and boosting stations. We estimate that, while about 16 Bcf of natural gas might potentially be emitted from these gathering and boosting stations on Federal and Indian leases, units, or communitization agreements, these sources are unlikely to be located on Federal surface lands. If located on lease, they are located after the natural gas measurement point under a rights-of-way authorization and owned by an entity other than the Federal or Indian lessee. As such, we note the potential emissions from that source but do not include it in the table.

Methodology for Table 2.7b

1. Natural Gas Flaring

The ONRR provided BLM with natural gas flaring data reported to its OGOR system. The data indicates that the gas flared from operations producing from Federal and Indian leases contains a mix of gas produced from various mineral estates, including Federal and Indian mineral estates and non-Federal and non-Indian mineral estates (i.e., state-owned or privately-owned minerals). Meaning, the ONRR data includes volumes for Federal gas that was flared, Indian gas that was flared, and "mixed" gas that was flared that could include gas from the Federal, Indian, or other mineral estate.

To estimate the portion of Federal and Indian mineral estate natural gas flared in 2016, we took the portions reported as "Federal" or "Indian" and added the share of the "mixed" gas that we estimated to come from the Federal or Indian mineral estate. We calculated those shares using ONRR-provided data for the share of "mixed" gas production that it allocates to the Federal and Indian mineral estates.

2. Natural Gas Venting

The EPA provided the BLM with "whole gas" emissions data, by "petroleum systems" and "natural gas systems" and by source category, derived from the 2018 GHG Inventory's U.S. methane emissions estimates. We calculated estimates specific to Federal and Indian leases by taking 8.10% of the EPA's national estimate for the petroleum systems' whole gas emissions and 11.17% of the EPA's national estimate for the natural gas systems' whole gas emissions. These downward adjustments reflect the share of onshore U.S. crude oil and natural gas production in 2016, respectively, that came from Federal and Indian lands.[20]

The BLM notes that it adjusted its methodology for estimating losses from liquids unloading. In the 2016 RIA, the BLM used a bottom-up approach for this source, rationalizing that "the GHG Inventory data suggest a high degree of variability across regions, and also within regions relevant to natural gas production on Federal and Indian lands" (2016 RIA at 18). The BLM believes that using a top-down estimation for all sources of venting is appropriate given the consistency of this approach and for transparency, since the 2018 GHG Inventory reports national emissions factors for liquids unloading.[21]

[20] These percentages were calculated using the following sources. ONRR production data for onshore Federal and Indian crude oil and natural gas production; available on the ONRR website: https://www.onrr.gov/About/production-data.htm. EIA production for onshore crude oil production, available on the EIA website: https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm. EIA production for onshore natural gas production, available on the EIA website: https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm.

[21] See EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2016. Annex 3 Methodological Descriptions for Additional Source or Sink Categories at Table 3.6-7: Activity Data for Natural Gas Systems Sources, for All Years.

Comparison of Venting and Flaring Estimates

To show the change in estimated venting and flaring over time, we compare the various estimates and provide a rationale for changes.

Table 2.7c: Venting and Flaring Estimates for 2008, 2014, and 2016 (All Volumes in Bcf)

Year of Losses	**2008**	**2014**	**2016**
Source of estimate	GAO 2010	BLM's 2016 RIA	BLM's 2018 RIA
Scope	Federal leases	Federal and Indian leases	Federal and Indian leases
Flared Gas	28	80.9	68.1
Well Completions and Workovers	30	1.12	0.76
Pneumatic Devices	16		
Pneumatic Controllers		14.93	11.7
Pneumatic Pumps		2.32	1.68
Gas Engines		1.06	1.26
Compressors		0.52	0.40
Liquids Unloading	17	3.26	0.98
Storage Tanks	18	2.94	0.90
Fugitives		4.01	3.74
Glycol Dehydrators	7		
Other	10		
Total	126	111	89

The BLM's estimates differ markedly from the GAO's estimates for 2008. There are several possible explanations for these discrepancies. The BLM notes that this rationale was explained in the 2016 RIA as well (2016 RIA at 18-19).

First, since 2010, the regulatory landscape has changed, with action on the Federal and State levels. In 2012, the EPA finalized Oil and Natural Gas Sector: New Source Performance Standards (NSPS), 40 CFR part 60, subpart OOOO, which established standards for EPA's regulation of VOC emissions from "new," "reconstructed," or "modified" sources in the oil and natural gas sectors.[22] In 2016, the EPA finalized NSPS 40 CFR part 60, subpart OOOOa, which addresses additional sources of emissions from new, reconstructed, and modified sources in the oil and natural gas sectors. The NSPS regulations apply to operations nationwide, including those on Federal and Indian lands, and have a co-benefit of reducing the loss of natural gas from certain sources.

Further, several States have published regulations and policies that have impacted Federal leases in those jurisdictions. Since 2008, the States of Colorado, Utah, Wyoming, and California have adopted regulations addressing emissions from oil and natural gas production. In addition, the

[22] The EPA also finalized National Emission Standards for Hazardous Air Pollutants (NESHAP) Rule, which places certain control requirements.

North Dakota Industrial Commission approved policies in 2014 aimed at reducing the flaring of natural gas from oil wells.

Second, the amount of flared oil-well gas has increased dramatically since 2008. Increased oil production from tight oil and other unconventional formations without commensurate increases to the gas transportation and processing infrastructure has led to the flaring of large volumes of associated gas.

Third, the GAO based most of its estimates for vented gas on emission factors from the EPA. However, we note that since 2010, the EPA revised its emission factors for gas well liquids unloading and well completions. In addition to the EPA's work, additional research has focused on the loss of gas from oil and gas wells and production sites.

Lastly, regarding volumes of flared gas reported to ONRR, the GAO report identified that not all flared volumes were reported by operators. The data show that since 2008, the reported volumes of flared gas have increased quite dramatically. While these increases likely reflect the increased oil production over that period, they may also reflect the increased reporting of flared volumes. Interviews with BLM field personnel indicate that some field offices began to specify ONRR reporting obligations as a condition of approval to flare.

The BLM also notes the decrease in gas flaring in the 2016 RIA (for 2014) and the 2018 RIA (for 2016). From 2015 to 2016, the BLM finds that gas flaring decreased 30% and gas venting decreased an estimated 3%, while Federal and Indian oil and gas production decreased by only 10% and 6%, respectively.

Table 2.7d: Federal and Indian Venting, Flaring, and Oil and Gas Production, FY 2015 - 2016

Metric	FY 2015	FY 2016	% Change
Flared Gas (Bcf)[1]	96.7	68.1	-30%
Vented Gas (Bcf)[2]	22.0	21.4	-3%
Total (Flared and Vented; Bcf)	118.7	89.5	-25%
Federal/Indian Oil Production (MMbbl)[3]	238.5	214.8	-10%
Federal/Indian Gas Production (Bcf)[4]	3.69	3.46	-6%

[1] Estimated from data reported by operators to ONRR's OGOR, https://www.onrr.gov/ReportPay/production-reporting.htm.

[2] The EPA's national emissions estimates in the 2018 Greenhouse Gas Inventory and 2017 Greenhouse Gas Inventory, adjusted downward based on the share of U.S. crude oil and natural gas production in 2016 and 2015, respectively, which came from Federal and Indian lands, https://www.onrr.gov/About/production-data.htm.

[3] Oil production volumes "subtotal onshore only," available on the ONRR website, https://www.onrr.gov/About/production-data.htm.

[4] Gas production volumes "subtotal onshore only," available on the ONRR website, https://www.onrr.gov/About/production-data.htm.

Although we present the 2016 flaring data in this background section for additional context, we use 2015 flaring levels and data for the baseline for estimating the impacts of this rule, as

presented in the results in Section 4. The BLM believes that the 2015 baseline flaring data is appropriate for several reasons. First, although flaring dipped in 2016, the BLM believes that dip was a function of reduced drilling and completion activity due to market conditions. Also, while more recent data may be available, the reported data are often adjusted in arrears to the reporting system. Further, we believe the 2015 flaring data is appropriate for analysis over the longer evaluation period, as we are seeing a rebound of crude prices which, according to projections, will continue in the future.[23] In addition, using the same flaring data for the baseline in this RIA as in the 2016 RIA helps to maintain consistency among the two analyses.

2.8 Existing Federal and State Regulations

The removal or revision of requirements in the 2016 rule would not leave oil and gas operations on Federal and Indian leases unregulated. The development and production of oil and gas are regulated under a framework of Federal and State laws and regulations. Several Federal agencies implement Federal laws and requirements, while each State in which oil and gas is produced has one or more regulatory agencies that administer State laws and regulations. These existing Federal and State regulations are incorporated in the baseline for this RIA to the extent possible.

State laws apply on Federal lands except when they are preempted by Federal law. Accordingly, the drilling, completion, and production operations of oil and gas wells on Federal lands are subject to both Federal and State regulation. If the requirements of a State regulation are more stringent than those of a Federal regulation, for example, the operator will comply with both the State and the Federal regulation by meeting the more stringent State requirement.

Tribal and Federal laws apply to oil and gas drilling, completion, and production operations on tribal lands. Operators on tribal lands will comply with both tribal and Federal regulations by assuring that they are in compliance with the stricter of those rules.

Regardless of any difference in operational regulations, operators on Federal lands must comply with all Federal, State, and local permitting and reporting requirements. On Indian lands, they must comply with all Federal and tribal permitting and reporting requirements.

Since 2010, the regulatory landscape has changed, with action on the Federal and State levels. In 2012, the EPA finalized Oil and Natural Gas Sector: NSPS, 40 CFR part 60, subpart OOOO, which established standards for EPA's regulation of VOC emissions from new, modified, and reconstructed sources in the oil and natural gas sectors. It does not address sources in existence prior to the date the NSPS was proposed, unless those sources are modified or replaced at some future time. NSPS 40 CFR part 60, subpart OOOO addresses emissions from hydraulically fractured gas well completion operations, storage vessels emitting more than 6 tons per year of uncontrolled VOC, continuous-bleed pneumatic controllers, and other sources. It applies to operations nationwide, including those on Federal and Indian lands, and it has a co-benefit of reducing the loss of natural gas from certain sources.

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[23] U.S. Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018), *available at* https://www.eia.gov/outlooks/aeo/

In addition, in 2016, the EPA finalized NSPS 40 CFR part 60, subpart OOOOa, which addresses VOC and GHG emissions from hydraulically fractured oil and natural gas well completions, pneumatic pumps, fugitive emissions, and other sources. The EPA recently proposed to delay the requirements for fugitive emissions, pneumatic pumps at well sites, and professional engineer certification for close vent systems for two years. [24] The EPA has not finalized this proposal. The EPA had already convened a proceeding for reconsidering the final OOOOa rule.[25] Like the NSPS 40 CFR part 60, subpart OOOO, this regulation addresses new, modified, and reconstructed sources in the oil and natural gas sectors, but not existing sources. It also applies to operations nationwide, including those on Federal and Indian lands, and would have a co-benefit of reducing the loss of gas from certain sources.

Several States have published regulations and policies that have impacted Federal leases in those jurisdictions. Below is a summary of selected State regulations and policies that have the effect of limiting the waste of gas from production operations in the States where the production of oil and gas from Federal and Indian leases is most prevalent.

Alaska: Historically, the State of Alaska had high rates of flaring, but the State adopted regulations in the 1970s to address the problem.[26] Since then, the State of Alaska has prohibited venting or flaring of gas except in narrowly defined circumstances: Testing a well before regular production; fuel that maintains a continuous flare; *de minimis* venting of gas incidental to normal oil field operations; and flaring or venting gas for no more than 1 hour during an emergency or operational upset. The practical effect is to drive widespread reinjection of associated gas into the field for conservation and oil recovery purposes. Alaska estimates that roughly 0.4 percent of gas production is flared, which is far lower than in most other States.

Colorado: Colorado Oil and Gas Conservation Commission regulations restrict the venting or flaring of natural gas. 2 COLO. CODE REGS. § 404-1-912. Under those regulations, "[t]he unnecessary or excessive venting or flaring of natural gas from a well is prohibited." An operator must obtain prior approval from the Commission for venting or flaring, "[e]xcept for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, or a productivity test." Gas flared, vented, or used on the lease must be estimated using a gas-to-oil ratio test or other approved method and reported on a monthly basis. Colorado has reduced venting through air quality regulations of emissions of hydrocarbons and other VOCs from the oil and natural gas industry.[27] The Colorado Department of Public Health and Environment, Air Quality Control Commission has instituted regulations similar in many ways to the EPA's existing NSPS for new, reconstructed, and modified hydraulically fractured gas wells and gas processing facilities. The Colorado regulation incorporates some aspects of EPA's NSPS 40 CFR part 60, subpart OOOO by reference, and expands upon the EPA standards in other areas. For example, the Colorado rule requires operators to control emissions from well

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[24] 82 FR 27645 and 82 FR 27641

[25] 82 FR 25730 (June 5, 2017).

[26] Alaska Administrative Code Title 20 - Chapter 25 235. Gas Disposition.

[27] Colorado Air Quality Control Commission Regulations, Regulation 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides).

operations (completions and recompletions) for all hydraulically fractured oil and gas wells. It extends the requirements for pneumatic controllers and storage tanks to cover existing, rather than just new, devices and facilities. It also requires operators to implement a comprehensive instrument-based LDAR program, sets standards for liquids unloading similar to those in the BLM's 2016 rule, and includes other measures.

Montana: Montana has had limits on venting and flaring in place for some years.[28] Produced gas vented to the atmosphere at a rate exceeding 20 Mcf per day that continues for more than 72 hours must be burned. After completion of a gas well, no gas may be permitted to escape, except gas required for periodic testing or cleaning of the well bore. If, after well completion, the operator intends to flare gas production in excess of 100 Mcf per day, the operator must obtain a variance from the State oil and gas board. The operator must submit a production test and a statement justifying the need for a variance, including information such as the estimated gas reserves, the proximity of the well to market, and the potential for reinjection. The board may elect to restrict production until the gas is marketed or otherwise beneficially used.

New Mexico: Under New Mexico's regulations, an operator is prohibited from venting or flaring associated gas from a well after 60 days following the well's completion. However, upon application by the operator, the state regulatory agency may grant an exception from this restriction "when the flaring or venting of casinghead gas appears reasonably necessary to protect correlative rights, prevent waste or prevent undue hardships on the applicant." The New Mexico regulation requires that lost associated gas be flared, rather than vented, and that estimated volumes of flared gas be reported. New Mexico requires operators to submit a Gas-Capture Plan with an APD. The Gas-Capture Plan must contain: (1) evidence of operator coordination with a mid-stream company, (2) information on how the well will be connected to a gathering system, (3) identification of where the gas will be processed, (4) statement that the mid-stream company can take anticipated gas upon completion of the well, and (5) a statement of alternatives to flaring (power generation, removal of natural gas liquids, etc.).

North Dakota: In March 2013, the Industrial Commission of North Dakota adopted a policy to reduce flaring, and it followed this with an enforceable order adopted in July 2014.[29] The policy and order require well operators to meet flaring reduction targets according to a prescribed timeline. The gas-capture targets for each operator start with a target of capturing at least 74 percent of production by October 2014 and then rise over time, culminating with a target of capturing at least 91 percent of production by November 2020.[30] The operator may show compliance with the target by well, field, county, or statewide. The policy provides for oil production to be restricted from wells where the operator does not meet the flaring reduction targets. Production is restricted to no more than 200 barrels of oil per day for those wells capturing more than 60 percent of the gas production, but less than the applicable target

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[28] Administrative Rules of Montana, Title 17-Chapter 8-Subchapter 16 Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit.

[29] https://www.dmr.nd.gov/oilgas/or24665.pdf

[30] Specifically, the targets for gas capture are: 74 percent of the gas by October 1, 2014; 77 percent by January 1, 2015; 80 percent by April 1, 2016; 85 percent by November 1, 2016; 88 percent by November 1, 2018; and, 91 percent by November 1, 2020. North Dakota Industrial Commission Order 24665 Policy/Guidance Version 102215 (Oct. 22, 2015).

percentage. Production is restricted to no more than 100 barrels of oil per day from those wells capturing less than 60 percent of produced gas.

Utah: Utah's regulatory restrictions on the flaring of associated gas are found in section R649-3-20 of the Utah Administrative Code. That regulation allows for up to 1,800 Mcf of associated gas to be flared from an individual well on a monthly basis without approval. The regulation also allows for necessary flaring during production tests and for the "unavoidable or short-term" venting or flaring of gas without approval. If an operator wishes to vent or flare associated gas in circumstances not expressly provided for in the regulation (e.g., where the operator finds conservation of the gas to be not economically viable), then the operator may request approval for such venting or flaring from the State regulatory agency. In addition, the Utah Department of Environmental Quality has issued regulations addressing emissions from pneumatic controllers and storage vessels as well as fugitive emissions from oil and gas wellsites.[31] Since the promulgation of the 2016 rule, the State of California has also issued new regulations that: require quarterly monitoring of methane emissions from oil and gas wells, compressor stations and other equipment involved in the production of oil and gas; impose limitations on venting from natural-gas-powered pneumatic devices and pumps; and require vapor recovery from tanks under certain circumstances.[32]

Wyoming: Wyoming Oil and Gas Conservation Commission rules (055-3 WYO. CODE R. § 39) impose restrictions on venting and flaring. The Wyoming rules authorize venting and flaring under the following circumstances: (1) Emergencies; (2) Well purging and evaluation tests; and (3) Production tests (for 15 days, unless a longer period is authorized). In addition, the rules authorize the flaring of up to 60 Mcf of gas per day from individual oil wells. (Associated gas may be vented where the rate does not exceed 20 Mcf per day.) An operator may also apply for authorization to flare in other circumstances. An operator's application for authorization to flare must include, among other information, a gas-capture plan identifying gas gathering and transportation facilities in the area, the name of gas gatherers providing "gas take-away capacity," and information on the gas gathering line to which the operator proposes to connect. The Wyoming Department of Environmental Quality adopted regulations on May 19, 2015, to reduce emissions of VOCs in the Upper Green River Basin nonattainment area, which does not meet the air quality standards for ozone pollution.[33] The regulations require operators to control emissions from new and existing storage tanks with uncontrolled emissions of 4 or more tons per year, by 2017, and to control emissions from existing pneumatic pumps (as of January 1, 2014) by 2017. The regulations also require existing pneumatic controllers (as of January 1, 2014) to be low-bleed or zero-bleed by 2017, and they require operators to implement an instrument-based LDAR program with quarterly inspections, by 2017. Further, the regulations establish requirements on additional emissions sources.

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[31] UTAH ADMIN. CODE r.307-501–510.

[32] CAL. CODE REGS. Tit. 17, §§ 95665–95677.

[33] The BLM received an advanced copy of the final rule but do not have a citation with which the public can access the regulation.

2.9 Industry Classifications

Most crude oil and natural gas entities are classified under the North American Industry Classification System (NAICS) 211. This rule directly affects entities classified within the Crude Petroleum and Natural Gas Extraction (211111), Natural Gas Liquid Extraction (211112), Drilling of Oil and Natural Gas Wells (213111), and Support Activities for Oil and Gas Operations (213112) industries. Other industries include various distribution, transportation, and storage industries.

The small entities affected by the regulatory action include small businesses in Oil and Gas Extraction, Drilling, and Support. We identify the population of affected entities in accordance with the Small Business Administration (SBA) size standards developed to carry out the purposes of the Small Business Act.[34] Based on these standards (also described below) the vast majority of businesses in the affected industries are considered small entities.

Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA as an individual, limited partnership, or small company considered being at "arm's length" from the control of any parent companies, with fewer than 1,250 employees. For firms drilling oil and gas wells, the threshold is 1,000 employees. For firms involved in support activities, the standard is annual receipts of less than $38.5 million.

To estimate the percentage of small entities involved in the affected industries, we reference Tables 2.9a and 2.9b. Table 2.9a illustrates that, in 2012, the vast majority of establishments in the affected oil and gas sectors were classified as "small," as defined by the SBA. Of the establishments involved in crude petroleum and natural gas extraction, 99% had fewer than 1,000 employees. Of the establishments involved in natural gas liquids extraction, 79% had fewer than 1,000 employees. Of the establishments involved in the drilling of oil and gas wells, over 98% had fewer than 1,000 employees. We note that the SBA size standards for crude petroleum and natural gas extraction and the natural gas liquids industries are higher than 1,000 employees; therefore, the percent of small businesses in these industries will likely be slightly higher than 99% and 79%, respectively. Table 2.9b illustrates that in 2012, of the establishments involved in oil and gas support, 96% had annual receipts of less than $35 million.

Based on these national data, the preponderance of entities involved in developing oil and gas resources are small entities as defined by the SBA. As such, it appears that a substantial number of small entities will be potentially affected by the final rule.

[34] Code of Federal Regulations, Title 13, Chapter I, Part 121, Subpart A, Section 121.201.

Table 2.9a Oil and Gas Establishments by Employment, Receipts, and Average Receipt per Firm – (2012)

NAICS Code	NAICS Name	Employee Size	Number Of Firms	Percent of All Firms	Receipts ($1,000)	Average Receipt per Firm ($1,000)
211111	Crude Petroleum and Natural Gas Extraction	0-4 employees	4,520	69.2%	$ 5,679,769	$ 1,257
		5-9 employees	933	14.3%	$ 4,245,124	$ 4,550
		10-19 employees	495	7.6%	$ 6,449,805	$ 13,030
		20-99 employees	399	6.1%	$ 18,612,686	$ 46,648
		100-499 employees	97	1.5%	$ 20,060,434	$ 206,809
		500-999 employees	26	0.4%	$ 32,115,176	$ 1,235,199
		<20 employees	5,948	91.0%	$ 16,374,698	$ 2,753
		<500 employees	6,444	98.6%	$ 55,047,818	$ 8,542
		<1,000 employees	6,470	99.0%	$ 87,162,994	$ 13,472
		>1,000 employees	66	1.0%	$ 185,096,970	$ 2,804,500
		any size	6,536	100.0%	$ 276,076,578	$ 42,239
211112	Natural Gas Liquid Extraction	0-4 employees	60	42.0%	$ 203,474	$ 3,391
		5-9 employees	17	11.9%	$ 148,498	$ 8,735
		10-499 employees	30	21.0%	$ 100,772	$ 3,359
		500-999 employees	6	4.2%	$ 1,366,827	$ 227,805
		<10 employees	77	53.8%	$ 351,972	$ 4,571
		<500 employees	107	74.8%	$ 452,744	$ 4,231
		<1,000 employees	113	79.0%	$ 1,819,571	$ 16,102
		>1,000 employees	30	21.0%	$ 24,443,361	$ 814,779
		any size	143	100%	$ 49,236,136	$ 344,309
213111	Drilling Oil and Gas Wells	0-4 employees	1,191	55.6%	$ 657,906	$ 552
		5-9 employees	258	12.0%	$ 378,134	$ 1,466
		10-19 employees	225	10.5%	$ 633,316	$ 2,815
		20-99 employees	303	14.1%	$ 2,686,952	$ 8,868
		100-499 employees	108	5.0%	$ 4,592,918	$ 42,527
		500-999 employees	15	0.7%	$ 1,684,645	$ 112,310
		<20 employees	1,674	78.1%	$ 1,669,356	$ 997
		<500 employees	2,085	97.2%	$ 8,949,226	$ 4,292
		<1,000 employees	2,100	97.9%	$ 10,633,871	$ 5,064
		>1,000 employees	44	2.1%	$ 21,281,060	$ 483,660
		any size	2,144	100%	$ 33,262,941	$ 15,514

Source: U.S. Census Bureau, Statistics of U.S. Businesses. Data available at https://www.census.gov/data/datasets/2012/econ/susb/2012-susb.html.

Table 2.9b: Oil and Gas Support Activities by Receipt Size, Receipts, and Average Receipt per Firm – 2012

NAICS Code	NAICS Name	Receipt Size ($)	Number of Firms	Percent of All Firms	Receipts ($1,000)	Average Receipt per Firm ($1000)
213112	Support Activities for Oil and Gas Operations	<100,000	1,194	13%	$ 72,652	$ 61
		$100,000-499,999	3,277	37%	$ 821,035	$ 251
		$500,000-999,999	1,086	12%	$ 789,848	$ 727
		$1,000,000-2,499,999	1,215	14%	$ 1,964,944	$ 1,617
		$2,500,000-4,999,999	788	9%	$ 2,750,642	$ 3,491
		$5,000,000-7,499,999	331	4%	$ 1,966,673	$ 5,942
		$7,500,000-9,999,999	205	2%	$ 1,720,148	$ 8,391
		$10,000,000-14,999,999	189	2%	$ 2,234,200	$ 11,821
		$15,000,000-19,999,999	131	1%	$ 2,059,589	$ 15,722
		$20,000,000-24,999,999	72	1%	$ 1,489,268	$ 20,684
		$25,000,000-29,999,999	43	0%	$ 967,448	$ 22,499
		$30,000,000-34,999,999	30	0%	$ 941,771	$ 31,392
		$35,000,000-39,999,999	34	0%	$ 1,068,553	$ 31,428
		$40,000,000-49,999,999	32	0%	$ 1,091,868	$ 34,121
		$50,000,000-74,999,999	61	1%	$ 3,229,182	$ 52,937
		$75,000,000-99,999,999	23	0%	$ 1,455,563	$ 63,285
		$100,000,000+	166	2%	$ 66,022,182	$ 397,724
		<$35,000,000	8,561	96%	$ 17,778,218	$ 2,077
		>$35,000,000	316	4%	$ 72,867,348	$ 230,593
		Any Size	8,877	100%	$ 90,645,566	$ 10,211

Source: U.S. Census Bureau, Statistics of U.S. Businesses. Data available at https://www.census.gov/data/tables/2012/econ/susb/2012-susb-annual.html.

3. Estimating Benefits and Costs

3.1 Analytical Framework

The final rule replaces the 2016 rule's requirements in subpart 3179 with requirements similar to those of NTL-4A. Notable improvements on NTL-4A in this final rule include: codifying a general requirement that operators flare, rather than vent, gas that is not captured (§ 3179.6); requiring persons conducting manual well purging to remain onsite in order to end the venting event as soon as practical (§ 3179.104); and, providing clarity about what does and does not constitute an "emergency" for the purposes of royalty assessment (§ 3179.103).

The final rule removes almost all of the requirements in the 2016 rule that we estimated would impose a compliance burden on operators and generate benefits of gas savings or reductions in methane emissions. Also, for the most part, the final rule removes the administrative burdens associated with the 2016 rule's subpart 3179. The 2016 rule contained 24 distinct information collection activities. The 2018 final rule contains only 5 information collection activities. The burdens associated with these remaining items are not substantial relative to those of the 2016 rule.[35]

The analysis incorporates state regulations and EPA regulations (at Subpart OOOO and Subpart OOOOa) into the baseline, from which it measures the impacts of the 2018 rule. The BLM considered the existing state and EPA requirements when estimated the number of affected units on wellsites, either at the present or in the future. For example, the Subpart OOOO and Subpart OOOOa requirements impact certain new, modified, or reconstructed sources of gas loss. For the BLM's baseline, where appropriate, we excluded from the baseline such units that the EPA's requirements cover. Similarly, we excluded from the baseline units that state regulations cover.

In conducting this RIA, the BLM reevaluated its original analysis for the 2016 rule and made some notable analytical changes.

First, we estimated impacts of the 2016 rule (the baseline), the 2018 final rule, and an alternative to the 2018 final rule, over the 10-year period from 2019 to 2028. For each of these scenarios, we assumed implementation of the 2016 rule would have begun in 2019. While we would generally expect operators to start taking action towards compliance sooner than 2019, because the major provisions of the 2016 rule have been administratively suspended or judicially enjoined for much of the time between December 2017 and the present, and because the regulated community has been aware of the BLM's efforts to suspend and revise the 2016 rule, we believe operators will be less likely to have done so in this case, instead waiting for the outcome of this rulemaking process.[36] The other implication of this update to the evaluation period is that certain provisions which were to have been phased in under the 2016 rule would

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[35] In the Supporting Statement for the Paperwork Reduction Act, the BLM estimates the total burden on industry from the remaining information collection activities to be 3,510 hours per year.

[36] In late February 2018, in the litigation challenging the 2016 rule, a representative from an industry trade group declared that the shifting regulatory landscape has created a situation in which many operators are not prepared (or not able) to come into immediate compliance with all requirements of the 2016 rule. See Declaration of Kathleen Sgamma, Attached to Memorandum in Support of Motion for Preliminary Injunction or Vacatur of Certain Provisions of the Rule Pending Administrative Review, Doc. 197, *Wyoming v. DOI*, 2:16-cv-00285-SWS (Feb. 28, 2018).

begin immediately under the baseline. So while we maintained the same cost and volumes of gas recovery assumptions, the timing of the gas capture requirements impacts would be immediate, rather than delayed, under the baseline.

Second, we reevaluated the underlying assumptions related to the LDAR requirements and the administrative burdens. As a result of this review, we maintained the underlying assumptions used in analyzing the LDAR requirements, but revised the underlying compliance cost assumptions used in analyzing the administrative burdens. A detailed discussion of those considerations is provided in Section 3.2.

Third, we revisited the estimation of the value of forgone emissions (climate benefits only). A detailed discussion of those considerations is provided in Section 3.3.

Fourth, the BLM updated the crude oil and natural-gas price assumptions based on current Energy Information Administration (EIA) forecasts.[37] We then adjusted each of those prices downward, using the same methodology as in the RIA for the 2016 rule, to reflect a more accurate price that operators would receive at the first point of sale (see 2016 RIA at 39).

While the BLM developed the 2016 rule, public commenters asserted that operators do not receive commodity prices listed in market indices, but rather lower prices, particularly for natural gas. Using ONRR data for 2015, we determined that it is reasonable to assume that an operator might receive prices for unprocessed natural gas and crude oil that are about 75% and 98%, respectively, of the published index prices.[38] We measured the discount to be the royalty revenues reported by ONRR divided by the royalty at 12.5% of the sales value. For processed gas and crude oil produced from Federal leases in 2015, the calculation returned 82% and 98%, respectively. Further, we compared the average sales value of unprocessed gas versus processed gas and found that price for unprocessed gas was 76% that of processed gas. During the 2016 rule process, we received additional feedback that the price received for natural gas could be even lower. Given those considerations, we determined in the 2016 RIA that it was appropriate to assume a natural gas price that was 75% of the EIA's projections. We carried that assumption forward in this RIA. Table 3.1, shows the projected commodity prices used in the 2016 RIA and in this analysis.[39] However, we also present a sensitivity analysis where we present results using a natural gas price that is 89% of the index price (see Section 4 and Section 7.3.1). Ultimately, the BLM believes that with this treatment of natural gas price, it is constraining the likely outcomes of this regulatory action.

The BLM also corrected a calculation error in the 2016 RIA, by which it had used the unadjusted natural gas prices to calculate the royalty impacts of the gas capture requirements. This miscalculation attributed higher royalties to the 2016 rule's gas capture requirements and therefore to the 2016 rule, in general. The BLM also corrected the discount rate by with it had calculated royalties that would be deferred. In the 2016 RIA, the BLM used a rate of 7% as the "opportunity cost" of oil and gas deferred, even when presenting the NPV of royalties using a 3% discount rate. For the 2018 RIA, we use a rate of 7% and 3% as the opportunity cost of oil

[37] EIA, Annual Energy Outlook 2018, released February 18, 2018.

[38] See Natural Resources Revenue data at https://revenuedata.doi.gov/

[39] The BLM also ran a sensitivity analysis for a higher natural gas price, see results in Section 7.3.1.

and gas deferred when presenting the NPV of royalties using a 7% and 3% discount rate, respectively. The BLM's 2016 RIA estimated that the rule would result in additional total royalties, over the 10-year period 2017-2026, of $65.4 million (NPV using a 7% discount rate) or $82.3 million (NPV using a 3% discount rate) (2016 RIA at 117). The BLM corrected the calculation and determined that it should have reported additional total royalties of $45.8 million (NPV using a 7% discount rate) or $103 million (NPV using a 3% discount rate). See Section 7.4.

Table 3.1: Crude Oil and Natural Gas Price Forecasts, Used in the 2016 RIA and the 2018 RIA, 2019 - 2038

	2016 RIA		2018 RIA			
Year	Crude Oil Price Used ($/bbl)	Natural Gas Price Used ($/bbl)[1]	EIA Forecast – Crude Oil – West Texas Intermed-iate Spot ($/bbl)[2]	Crude Oil Price Used ($/bbl)	EIA Forecast – Natural Gas – Spot Price at Henry Hub ($/MMbtu)[2]	Natural Gas Price Used ($/Mcf)
2019	62.96	3.11	52.82	51.76	3.40	2.63
2020	69.70	3.43	66.93	65.60	3.69	2.86
2021	73.86	3.35	73.74	72.27	3.66	2.83
2022	77.14	3.37	76.93	75.39	3.69	2.86
2023	79.44	3.67	79.33	77.74	3.83	2.96
2024	81.27	3.87	80.34	78.73	3.94	3.05
2025	83.70	3.97	82.50	80.85	4.07	3.15
2026	86.63	3.86	83.45	81.78	4.12	3.19
2027	91.10	3.83	84.99	83.29	4.17	3.23
2028	93.43	3.87	86.32	84.60	4.19	3.24
2029	95.12	3.91	88.14	86.38	4.26	3.30
2030	98.28	3.91	89.16	87.38	4.26	3.30
2031	101.43	3.88	90.49	88.68	4.27	3.30
2032	104.68	3.90	91.63	89.80	4.27	3.31
2033	108.11	3.85	92.89	91.03	4.27	3.30
2034	110.20	3.84	93.98	92.10	4.27	3.30
2035	113.81	3.80	95.19	93.29	4.26	3.29
2036	115.98	3.79	95.82	93.91	4.35	3.37
2037	119.64	3.74	98.29	96.33	4.36	3.38
2038	122.45	3.70	99.40	97.42	4.43	3.43

[1] Gas prices used in the 2016 RIA excecpt for the miscalculations.
[2] Source for index prices: EIA, Annual Energy Outlook 2018, Table 1. Total Energy Supply, Disposition, and Price Summary. Reference case. Henry Hub natural gas prices converted from MMbtu to Mcf using a factor of 1.032.

Fifth, we corrected a calculation error original to the 2016 RIA and carried forward in the RIA that accompanied the proposed rule. In the 2016 RIA, the BLM used an incorrect ratio to calculate VOC emissions reductions from estimated methane emissions reductions. The BLM

has corrected those previous VOC miscalculations in this RIA. See Section 4.5.8 for a discussion of the issue.

Sixth, the BLM recognizes that the baseline assumption that the 2016 rule's liquids unloading requirements would generate an impact is questionable. The 2016 RIA assumed that the 2016 rule's requirements would compel operators to install a plunger lift on a well that would otherwise conduct liquids unloading by venting to the atmosphere, noting that the results were likely overstated since the liquids unloading requirements of the 2016 rule did not actually require the installation of a plunger lift (2016 RIA at 66). The 2016 RIA further noted that, because the use of plunger lifts is common, it is possible that operators have already installed lift systems on wells where the installations are feasible and that installations would not be made at the remaining wells (2016 RIA at 66). We decided to maintain that assumption, for consistency, and report the impacts accordingly in Section 4. However, we also present the estimated impacts of the 2018 final rule with an alternate baseline, where the 2016 rule would not have compelled the installation of plunger lifts. See Section 7.3.2 for that analysis.

Finally, we provided further discussion, including additional quantitative analysis, regarding the potential adverse impact that the 2016 rule would have had on marginal wells and economic activity.

Except for those notable changes, this RIA generally uses the same underlying assumptions as in the RIA prepared for the 2016 rule, published in November 2016. More specifically, the BLM used the same per-unit cost assumptions and the same per-unit gas volumes recovered and emissions reductions for the equipment requirements. The BLM also used the same model used in the 2016 RIA for the gas-capture requirements but updated its analysis to account for the updated commodity price projections.

We believe that these assumptions still hold true and have not materially changed since November 2016. However, we recognize that, to the extent that operators have already undertaken compliance activities, the baseline estimated for this final rule could be overstated in terms of compliance costs, cost savings, and emissions reductions. However, other aspects of the rule could not be monetized and could lead to understatement.

The BLM received comments to the proposed 2018 rule supporting the aforementioned possibility of overstated impacts and making a number of other assertions that the BLM's estimated costs are overstated. On the other hand, we also note that during the rulemaking process for the 2016 rule and this 2018 final rule, the BLM received a substantial number of comments suggesting that the BLM's estimated compliance costs were inadequate and that the actual costs of the 2016 rule would be much higher. The petitioners in the litigation challenging the 2016 rule raised the same concerns. Higher estimated compliance costs of the 2016 rule's requirements, for the purpose of this analysis, would result in greater cost savings for this final deregulatory action.

While the BLM recognizes arguments that its compliance costs were underestimated, we have not revisited the estimated compliance costs or cost savings at this time, outside of the areas mentioned above.

3.2 Revisited Underlying Assumptions

3.2.1 Leak Detection and Repair Requirements – Leak Rates and Program Effectiveness

The BLM revisited the underlying assumptions that it used to estimate the impacts of the LDAR requirements in the 2016 RIA. In that analysis and in the preamble to the 2016 rule, the BLM provided a detailed account of the research studies and available data concerning the topic.

For the 2016 RIA, the BLM relied on data available in the EPA's Control Technique Guidelines (CTG).[40] In addition to providing its own description of the available research and data regarding fugitive emissions (leaks) and control technologies, the CTG provides data on estimated costs and emissions reductions for various levels of inspection frequencies (annual, semi-annual, and quarterly) on different well and wellsite types (gas wells, oil wells with less than 300 gas-to-oil (GOR) ratio, and oil wells with greater than 300 GOR). The CTG data which the BLM used for the 2016 RIA relies on estimates that the EPA developed regarding leak rates and program effectiveness.

The BLM revisited the research concerning observed and estimated leak rates in order to evaluate the assumptions used in the 2016 RIA and to determine whether the same assumptions should be carried forward for this RIA as discussed below.

The BLM again reviewed a 2014 Carbon Limits study,[41] a non-peer-reviewed document put together for the Clean Air Task Force, which provides a comparison of observed emissions rates from wellsites and well batteries. The Carbon Limits study distinguishes between leaks, vents, and overall emissions. At wellsites and well batteries, it finds average leak rates of 0.4 scf/minute, average vent rates of 1.2 scf/minute, and average emissions of 2.1 scf/minute. The rates presented by other studies were all average emissions for wellsites and well batteries (and not specific to leak rates). Carbon Limits reports average emissions rates from other studies of 0.23, 0.8, and 3.1 scf/minute.

The average leak rate observed by Carbon Limits translates to about 210 Mcf/year. We note that the wellsites that Carbon Limits studied were oil and gas wellsites and the authors did not distinguish between leak rates for oil wells and gas wells. By comparison, the BLM based its 2016 RIA on data that it inferred from the CTG analysis, indicating an average leak rate of 318 Mcf/year for gas wellsites, 72 Mcf/year for oil wellsites with <300 GOR, and 160 Mcf/year for oil wellsites with >300 GOR. In the 2016 RIA, the BLM inferred gas recovery rates using data from the CTG analysis, Tables 9-11, 9-12, and 9-13, for annual, semi-annual, and quarterly programs, respectively (CTG, pp. 9-25 – 9-27). For an annual LDAR program, the BLM used average gas recovery assumptions of 127 Mcf/year for gas wellsites, 29 Mcf/year for oil wellsites with <300 GOR, and 64 Mcf/year for oil wellsites with >300 GOR. The EPA had

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[40] EPA, Control Technique Guidelines for the Oil and Natural Gas Industry. October 2016. Available on the web at https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf.

[41] Carbon Limits. Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras. CL report CL-13-27. March 2014.

developed these gas recovery rates based on leak rates and the assumed program effectiveness (described later). In developing the estimated leak rates, the EPA used average leak rates for individual pieces of equipment and calculated emissions for model sites, for each gas wellsites, oil wellsites with <300 GOR, and oil wellsites with >300 GOR.

In the 2016 RIA, the BLM provided estimates (based on EIA well productivity data for 2009) for the number of wellsites impacted for each of these site categories. According to those estimates and the average leak rate data in the CTG, we calculate a weighted average leak rate of about 236 Mcf/year per wellsite. Since this weighted average is higher than the 210 Mcf/year figure observed by Carbon Limits, we believe that the BLM's leak and reductions estimates in the 2016 RIA might have been overstated. Since the available Carbon Limits data is reasonably close to the data that the BLM derived from the CTG analysis, we have concluded that underlying assumptions used in the 2016 RIA on which we estimated gas recovery are not unreasonable. As such, we carried forward those assumptions for the purpose of this RIA.

Next, the BLM revisited the research concerning LDAR program effectiveness. The CTG references the EPA's white paper on "Oil and Natural Gas Sector Leaks," which found that optical gas imaging (OGI) monitoring programs could reduce emissions by 40% to 99% (CTG, p. 9-20). The CTG also discusses the assumptions made by the Colorado Air Quality Control Commission (CAQCC) in the economic impact analysis for its oil and gas emissions rule. The CAQCC, in estimating OGI monitoring effectiveness on storage vessels assumed 40% reductions for annual inspections, 60% reductions for quarterly inspections, and 80% reductions for monthly inspections (CAQCC, p. 27).[42] The CAQCC's analysis points to EPA data as the basis for its assumptions.

The CTG also discusses an EPA Protocol document that addresses Method 21 monitoring effectiveness. Using Method 21 data from the EPA Protocol document, the EPA estimated, for leaks defined as 10,000 ppm, that quarterly, semi-annual, and annual monitoring would achieve 67%, 55%, and 42% reductions, respectively. The EPA estimated, for leaks defined as 500 ppm, that quarterly, semi-annual, and annual monitoring would achieve 83%, 75%, and 68% reductions, respectively (CTG, p. 9-21).

Lastly, the CTG references the 2016 ICF International study,[43] a non-peer-reviewed study prepared for the Environmental Defense Fund that used data from a number of other studies, and from a Jonah Energy presentation, showing that its quarterly LDAR program achieved 78% emissions reductions in year 3. The EPA determined that the data in the study supported emissions reductions assumptions of 40%, 60%, and 80%, for annual, semi-annual, and quarterly monitoring programs, respectively (CTG, p. 9-21).

Based on the available data, the EPA concluded for its CTG analysis that an OGI-based LDAR program can reduce emissions by 40%, 60%, and 80%, for monitoring conducted on annual, semi-annual, and quarterly frequencies, respectively (CTG, p. 9-22).

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[42] CAQCC. Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S. 2014. Available on the web at http://www.ematrix.erg.com/files/control/BP%20Doc%20Colorado%201.pdf.

[43] ICF International. Leak Detection and Repair Cost-Effectiveness Analysis. Prepared for Environmental Defense Fund. December 4, 2015. Revised May 2, 2016.

The BLM has reviewed this information in the context of re-examining the 2016 rule's LDAR requirements and assessing whether using the same assumptions is appropriate in this context. While we cannot verify the basis for the original assumptions made by the CAQCC, the EPA's additional analysis of the Method 21 data suggests that the CTG assumptions may have underestimated the effectiveness of annual inspections or overstated the relative differences in effectiveness among programs of different inspection frequencies. The available data also suggest that there is a practical upper-bound to the effectiveness of a LDAR program. We note Jonah Energy's experience of 78% emissions reductions in year 3 of a quarterly program. To the extent annual LDAR programs are more effective than assumed in the CTG and in the RIA for the 2016 rule, an annual LDAR program would be relatively closer, in terms of private costs and benefits, to the semi-annual and quarterly LDAR programs. While the foregoing estimates are uncertain, the BLM has carried forward the LDAR effectiveness assumptions from the 2016 RIA in this RIA in order to maintain consistency between the two.

The BLM received comments arguing that the BLM's RIA for the proposed rule should have considered a range of approaches to LDAR in order to determine whether there is a less stringent LDAR program, short of complete rescission, that would still satisfy the BLM's goals of reducing unnecessary regulatory burdens on domestic energy development. The BLM appreciates the commenters' concern with examining alternative approaches to LDAR and, in response, notes the following. In the RIA for the 2016 rule, the BLM examined the impacts of a range of alternative approaches from LDAR. See 2016 RIA at 91-93. Specifically the RIA examined the five following LDAR alternatives: (1) Semi-annual inspections (adopted in the 2016 rule); (2) Quarterly inspections; (3) Semi-annual inspections, but annual inspections for oil wells with <300 GOR; (4) Semi-annual inspections, exempting oil wells with <300 GOR; and (5) Annual inspections. Note that the 2016 RIA estimated that the last three alternatives would have imposed fewer compliance costs than the alternative adopted in the 2016 rule. However, for all of the alternatives examined, compliance costs greatly outweighed cost savings (i.e., the value of the gas conserved). The annual inspections alternative was the least burdensome in terms of compliance costs. However, the 2016 RIA estimated that this alternative would impose costs of about $48 million per year while generating only $8 to $14 million in annual cost savings. Finally, when including estimates of benefits associated with foregone emissions (using the domestic social cost of methane), the BLM found net costs for all of the LDAR alternatives analyzed in the 2016 RIA. In light of this information, the BLM continues to believe that the rescission of the LDAR requirements of the 2016 rule is appropriate.

3.2.2 Administrative Burdens

The BLM also reviewed the various administrative burdens associated with the 2016 rule. During the inter-agency review process pursuant to E.O. 12866, the Office of Information and Regulatory Affairs (OIRA) within OMB requested that the BLM revisit previous estimates of administrative burdens. After further consultation with BLM State and field offices, the BLM made the determination that the previous estimates of administrative burdens presented in the RIA in the 2016 rule were underestimated. The BLM concluded that the previously estimated

administrative burdens were underestimated and adjusted those burden estimates upwards accordingly.

The BLM now estimates that the 2016 rule would pose administrative costs of about $14 million per year ($10.7 million to be borne by the industry and $3.27 million to be borne by the BLM). This final rule removes the vast majority of these burdens. By comparison, the final rule will only pose administrative burdens of $349,000 per year ($262,000 to be borne by industry and $86,900 to be borne by the BLM). The following tables show a summary of these data with detailed tables in the Appendix.

Table 3.2.2a: Revised Annual Industry Burdens

Scenario	Number of Responses	Total Hours	Total Burden ($)
2016 Rule (Baseline)	64,900	164,000	$10,700,000
2018 Final Rule	1,080	4,010	$262,000
Change	*(63,900)*	*(160,000)*	*($10,500,000)*

Table 3.2.2b: Revised Annual BLM Burdens

Scenario	Number of Responses	Total Hours	Total Burden ($)
2016 Rule (Baseline)	64,900	72,700	$3,270,000
2018 Final Rule	1,080	1,940	$86,900
Change	*(63,900)*	*(70,800)*	*($3,180,000)*

3.3 Estimating Forgone Domestic Climate Benefits

1. Social Cost of Methane

We estimate the forgone climate benefits from the final rule using a measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 is an estimate of the monetary value of impacts associated with marginal changes in CH_4 emissions in a given year.

Since publication of the RIA for the 2016 rule, several documents upon which the 2016 RIA relied have been rescinded. In particular, Section 5 of E.O. 13783, issued by the President on March 28, 2017, disbanded the earlier Interagency Working Group on Social Cost of Greenhouse Gases (IWG) and withdrew the Technical Support Documents[44] upon which the 2016 RIA relied for the valuation of changes in methane emissions.

E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent

[44] Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under E.O. 12866 (published August 26, 2016) and it's Addendum.

with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)).

OMB Circular A-4 establishes that an agency's analysis should "focus on benefits and costs that accrue to citizens and residents of the United States."[45] It further states, "where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately."[46] Since the guidance documents upon which the BLM had previously relied for global SC-CH_4 estimates were rescinded, the BLM has chosen to evaluate the forgone climate benefits using the interim domestic SC-CH_4 (see Section 7.2 in the Appendix for a discussion of the interim domestic SC-CH_4). The SC-CH_4 estimates presented here are interim values for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S. can be developed. In accordance with E.O. 13783 and OMB Circular A-4, they are adjusted to reflect discount rates of 3 percent and 7 percent and to present domestic rather than global impacts of climate change. The 7 percent rate is intended to represent the average before-tax rate of return to private capital in the U.S. economy. The 3 percent rate is intended to reflect the rate at which society discounts future consumption, which is particularly relevant if a regulation is expected to affect private consumption directly.

The Mineral Leasing Act (MLA) provides the BLM with authority to prescribe regulations to prevent the "waste" of oil and gas resources. (30 U.S.C. §§ 187, 225). The statute does not include climate-related benefits from changes in GHG emissions as factors that the BLM should consider in exercising this authority. Thus, the BLM does not consider the monetized benefits of avoiding GHG emissions as a statutory basis under the MLA for rulemaking in this area. However, as directed by E.O. 12866 and Circular A-4, the BLM has estimated all of the significant costs and benefits of this rule to the extent that data and available methodologies permit, consistent with the best science currently available. The 2016 rule stated that it was expected to result in climate-related and public health benefits by reducing methane emissions and hazardous air pollutants. This final rule will forgo the climate-related and health benefits associated with any emissions reductions from the 2016 rule.

Table 3.2 shows the domestic SC-CH_4 estimates used in this RIA to value the incremental change in methane emissions. In Section 7.2 in the Appendix, we provide additional detail about the development of the estimates and uncertainties.

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[45] OMB Circular A-4 at Section E.1.

[46] Ibid.

Table 3.2: Interim Domestic SC-CH_4, Using 7% and 3% Discount Rates*

	Interim Domestic SC-CH4 (2016$/metric ton)	
Year	**7%**	**3%**
2018	$52	$167
2019	53	171
2020	55	176
2021	58	181
2022	60	187
2023	63	193
2024	65	198
2025	68	204
2026	70	209
2027	73	215
2028	75	221
2029	78	226
2030	81	232

* The estimates are emission year specific and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

2. Social Cost of Carbon Dioxide

We estimate the climate benefits from the final rule using a measure of the domestic social cost of carbon dioxide (SC-CO_2). The SC-CO_2 is an estimate of the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year.

The SC-CO_2 was included in the 2016 RIA to measure the value of CO_2 additions coming from the combustion of natural gas that would have otherwise been vented. We note that the volume of gas that this applied to was very small and so the value of those emissions were considered to be de minimis (even using a global value of SC-CO_2). The reason why the volume was considered so small was because it did not include the gas capture requirement volumes, since those volumes were either going to be flared onsite or combusted downstream. Meaning, there were no CO_2 additions associated with the gas capture requirements.

Under this rule, the small volume of additional CO_2 emissions would no longer occur, offsetting the value of the forgone methane emission. However, as with the 2016 RIA, the value of this CO_2 volume is de minimis, particularly with the domestic SC-CO_2.

3.4 Discounted Present Value

There is a time dimension to estimates of potential costs and benefits. The 2018 final rule will result in: A reduction in compliance costs which would have been borne by operators in the future; foregone benefits associated with the recovery and sale of natural gas that would have been realized by operators; and foregone benefits associated with the reductions in natural gas emissions. We show the 2018 final rule's impacts over 10 years of implementation, from 2019-2028, using both 7% and 3% discount rates to show the NPV of cumulative impacts[47].

3.5 Uncertainty

The impacts presented in this analysis are estimates and are associated with uncertainty. These sources of uncertainty were noted in the RIAs for the 2016 rule and the 2017 Suspension Rule. These sources include uncertainties about:

- Operator behavior, whether the initial estimated compliance activity required by the 2016 rule was accurate, and whether operators undertook additional voluntary compliance activities since the 2016 rule published in November 2016;
- The estimated impacts, particularly for the gas-capture provisions. In the analysis developed for the 2016 rule, the BLM based its analysis on the EIA's crude-oil and natural-gas price forecasts but reduced those prices to account for the prices that operators might actually receive. For the gas-capture provisions, the BLM's assumed prices did not account for field-level differences;
- The amount of voluntary compliance currently occurring. If the actual level of voluntary compliance is higher than that assumed, then the estimated impacts of rescinding the 2016 rule's requirements will be lower than BLM's estimations;
- The impacts on marginal and low-production wells and the extent to which the 2016 rule would have resulted in the abandonment of reserves;
- The extent of damage to reservoirs from temporary shut-in;
- The extent to which the incremental costs of the 2016 rule would have shifted drilling activity to non-Federal lands;
- Leak rates and LDAR effectiveness;
- $SC\text{-}CH_4$, as described in the Appendix to this RIA; and
- The duration of curtailed production for the purpose of analyzing the 2016 rule's gas capture requirements. As discussed in Section 7.5, the BLM made the assumption that curtailed production would ultimately be produced 10 years later. It could be argued that the duration of curtailed production could either be shorter or longer, particularly on a well-by-well basis. The actual duration of the curtailment has implications on the cost estimates in the 2016 RIA and the cost savings estimates in the 2018 RIA. If the duration of curtailment, on the whole, were shorter than 10 years, than the costs of the 2016 rule would be lower and the cost savings of the 2018 rule would therefore be lower. On the other hand, if the duration of curtailment, on the whole, were longer than 10 years, than

[47] Net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows over a period of time.

the costs of the 2016 rule would be higher and the cost savings of the 2018 rule would therefore be higher.

Given the available data, we are not able to quantify the magnitude of the primary sources of uncertainty.

4. Results

This section presents the estimated impacts of the following three regulatory alternatives:

1. No Action Alternative / Baseline – The BLM retains and implements all of the 2016 rule's requirements;
2. 2018 Final Rule – The BLM modifies the requirements, as detailed in Section 2.3; and
3. Alternative 2 – The BLM retains and implements the 2016 rule's gas-capture requirements and the associated measurement/metering requirements while rescinding the operational and equipment requirements addressing vented volumes.[48]

4.1 Estimated Reductions in Compliance Costs

First, we examine the reductions in compliance costs, excluding the savings that would have been realized from product recovery (considered in sections 4.2 and 4.3). Tables 4.1a and 4.1b show the compliance costs of the 2016 rule (baseline or "no action" alternative), the 2018 final rule, and alternative 2.

Compliance Costs (Excluding Savings from Gas Recovery)

<u>No Action Alternative / Baseline:</u> Leaving the 2016 rule intact would result in substantial compliance costs. Over the 10-year evaluation period (2019-2028), we estimate total compliance costs of $1.362 billion – $1.637 billion (NPV using a 7% discount rate) or $1.715 billion – $2.079 billion (NPV using a 3% discount rate).

Reduction in Compliance Costs from the Baseline

<u>Final Rule:</u> The 2018 final rule will reduce compliance costs from the baseline. Over the 10-year evaluation period (2019-2028), we estimate a total reduction in compliance costs of $1.359 billion – $1.634 billion (NPV using a 7% discount rate) or $1.712 billion – $2.076 billion (NPV using a 3% discount rate).[49] There are expected to be very few compliance costs associated with the final rule, including the remaining administrative burdens.

<u>Alternative 2:</u> Alternative 2 is estimated to reduce compliance costs but by a smaller amount, relative to the proposal. If the 2016 rule's gas-capture and metering/measuring requirements were retained, over the 10-year evaluation period (2019-2028), we estimate a total reduction in compliance costs from the baseline of $770 million (NPV using a 7% discount rate) or $944 million (NPV using a 3% discount rate).

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[48] See Section 2.4 of this RIA for a discussion of these alternatives.

[49] The estimated reduction in compliance costs associated with the proposed rule is similar, but not identical, to the estimated compliance costs of the 2016 rule. The slight difference is due to the few administrative burdens that would be retained with the proposed rule.

Table 4.1a: Estimated Compliance Costs of the 2016 Rule (No Action/Baseline), 2018 Final Rule, and Alternative 2, Using a 7% Discount Rate to Annualize Capital Costs and to Calculate NPV ($ in millions)

	2016 Rule -- No Action/Baseline		2018 Final Rule		Alternative 2	
Year	Lower estimate	Higher estimate	Lower estimate	Higher estimate	Lower estimate	Higher estimate
2019	$127	$143	$0.35	$0.35	$10	$26
2020	$137	$157	$0.35	$0.35	$20	$40
2021	$187	$217	$0.35	$0.35	$70	$100
2022	$253	$287	$0.35	$0.35	$136	$170
2023	$271	$314	$0.35	$0.35	$154	$196
2024	$235	$282	$0.35	$0.35	$117	$165
2025	$214	$275	$0.35	$0.35	$96	$157
2026	$237	$305	$0.35	$0.35	$119	$188
2027	$239	$308	$0.35	$0.35	$122	$190
2028	$241	$308	$0.35	$0.35	$123	$190
NPV (7%)	$1,362	$1,637	$2.29	$2.29	$592	$867
Difference from baseline (NPV7)			($1,359)	($1,634)	($770)	($770)
Annualized difference (7%)			($194)	($233)	($110)	($110)

*Discounting done relative to 2018. **Totals may not sum due to rounding.

Table 4.1b: Estimated Compliance Costs of the 2016 Rule (No Action/Baseline), 2018 Final Rule, and Alternative 2, Using a 3% Discount Rate to Annualize Capital Costs and to Calculate NPV ($ in millions)

	No Action/Baseline		2018 Final Rule		Alternative 2	
Year	Lower estimate	Higher estimate	Lower estimate	Higher estimate	Lower estimate	Higher estimate
2019	$123	$139	$0.35	$0.35	$10	$25
2020	$133	$153	$0.35	$0.35	$19	$39
2021	$183	$213	$0.35	$0.35	$69	$100
2022	$249	$283	$0.35	$0.35	$135	$169
2023	$267	$309	$0.35	$0.35	$153	$196
2024	$230	$278	$0.35	$0.35	$116	$164
2025	$209	$271	$0.35	$0.35	$95	$157
2026	$232	$301	$0.35	$0.35	$118	$187
2027	$235	$303	$0.35	$0.35	$121	$189
2028	$237	$303	$0.35	$0.35	$122	$189
NPV (3%)	$1,715	$2,079	$2.89	$2.89	$771	$1,135
Difference from baseline (NPV3)			($1,712)	($2,076)	($944)	($944)
Annualized difference (3%)			($201)	($243)	($111)	($111)

*Discounting done relative to 2018. **Totals may not sum due to rounding.

4.2 Estimated Reduction in Benefits

The final rule will reduce benefits from the baseline, since estimated cost savings that would have come from product recovery would be forgone and the emissions reductions would also be forgone.

Table 4.2a shows estimated cost savings of the 2016 rule (baseline or "no action" alternative), the 2018 final rule, and alternative 2. Table 4.2b shows the estimated emissions reductions associated with each approach. Table 4.2c shows the estimated social benefits associated with each approach.

Cost Savings

No Action Alternative / Baseline: Leaving the 2016 rule intact would result in cost savings from natural gas recovery. Over the 10-year evaluation period (2019-2028), we estimate total cost savings of \$559 million (NPV using a 7% discount rate) or \$734 million (NPV using a 3% discount rate).

Forgone Cost Savings Relative to the Baseline

Final Rule: The final rule will result in forgone cost savings from natural gas recovery. Over the 10-year evaluation period (2019-2028), we estimate total forgone cost savings from natural gas recovery of \$559 million (NPV using a 7% discount rate) or \$734 million (NPV using a 3% discount rate).

Alternative 2: Alternative 2 estimated to result in forgone cost savings from natural gas recovery but by a smaller amount, relative to the proposal. If the 2016 rule's gas-capture and metering/measuring requirements were retained, over the 10-year evaluation period (2019-2028), we estimate total forgone cost savings from natural gas recovery of \$178 million (NPV using a 7% discount rate) or \$226 million (NPV using a 3% discount rate).

Environmental Benefits

No Action Alternative / Baseline: Leaving the 2016 rule intact would result in methane and VOC emissions reductions of about 175,000 – 180,000 tons per year and 79,000 – 80,000 tons per year, respectively. Over the 10-year evaluation period (2019-2028), we estimate total methane and VOC emissions reductions of 1.78 million tons and 798,000 tons, respectively.

Forgone Environmental Benefits

Final Rule: The final rule will result in forgone methane emissions reductions of an estimated 175,000 – 180,000 tons per year. Over the 10-year evaluation period (2019-2028), we estimate total forgone methane emissions reductions of 1.78 million tons. The final rule will result in forgone VOC emissions reductions of an estimated 79,000 – 80,000 tons per year. Over the 10-year evaluation period (2019-2028), we estimate total forgone VOC emissions reductions of 798,000 tons.

Alternative 2: We estimate that Alternative 2 would result in the same forgone methane and VOC emissions reductions, relative to the baseline, as the final rule. This was because the methane benefits of the 2016 rule were associated with the equipment requirements that would be rescinded under alternative 2.

Value of the Methane Reductions

No Action Alternative / Baseline: Leaving the 2016 rule intact would result in estimated methane emissions reductions. Over the 10-year evaluation period (2019-2028), we estimate total methane emissions reductions valued at $66 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or $259 million (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Value of the Forgone Methane Reductions

Final Rule: The final rule would result in estimated forgone methane emissions reductions. Over the 10-year evaluation period (2019-2028), we estimate total forgone methane emissions reductions from the baseline valued at $66 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or $259 million (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Alternative 2: We estimate that Alternative 2 (retaining the 2016 rule's gas-capture and metering/measuring requirements) would result in the same value of forgone methane reductions as the 2018 final rule. Alternative 2 would retain the 2016 rule's gas-capture requirements (aimed at reducing gas flaring) and rescind the 2016 rule's emissions-focused requirements (aimed at reducing the venting of methane). Since the BLM does not estimate any methane reductions associated with the gas-capture requirements and the final rule and Alternative 2 would both rescind the same emissions-focused requirements, we do not estimate any difference in forgone methane reductions between the final rule and Alternative 2.

Non-Monetized Forgone Benefits

The final rule is expected to have impacts that this analysis examines but does not include in the calculation of monetized costs and benefits. Although the analysis monetizes the forgone methane emissions reductions and the forgone carbon dioxide additions, the analysis does not monetize the costs to public health and the environment of forgoing VOC emissions reductions of 79,000 – 80,000 tons per year and forgoing emissions reductions of hazardous air pollutants. VOC and hazardous air pollutants pose negative impacts on climate, health, and human welfare.

Table 4.2a: Estimated Cost Savings Associated with Natural Gas Recovery for the 2016 Rule (No Action/Baseline), the 2018 Final Rule, and Alternative 2 ($ in millions)

Year	No Action/Baseline	2018 Final Rule	Alternative 2
2019	$43	$0	$19
2020	$52	$0	$26
2021	$65	$0	$39
2022	$70	$0	$44
2023	$84	$0	$57
2024	$94	$0	$66
2025	$117	$0	$88
2026	$129	$0	$100
2027	$131	$0	$101
2028	$129	$0	$98
NPV (7%)	$559	$0	$381
NPV (3%)	$734	$0	$507
Difference from baseline (NPV7)		($559)	($178)
Difference from baseline (NPV3)		($734)	($226)
Annualized difference (7%)		($80)	($25)
Annualized difference (3%)		($86)	($27)

*Discounting done relative to 2018. **Totals may not sum due to rounding.

Table 4.2b: Estimated Emissions Reductions of the 2016 Rule (No Action/Baseline), the 2018 Final Rule, and Alternative 2 (tons)

Methane Emissions Reductions*			
Year	**No Action/Baseline**	**2018 Final Rule**	**Alternative 2**
2019	175,000	0	0
2020	176,000	0	0
2021	176,000	0	0
2022	177,000	0	0
2023	177,000	0	0
2024	178,000	0	0
2025	178,000	0	0
2026	179,000	0	0
2027	179,000	0	0
2028	180,000	0	0
Total	1,780,000	0	0
Difference from baseline		(1,780,000)	(1,780,000)
VOC Emissions Reductions*			
Year	**No Action/Baseline**	**2018 Final Rule**	**Alternative 2**
2019	79,100	-	-
2020	79,200	-	-
2021	79,400	-	-
2022	79,500	-	-
2023	79,700	-	-
2024	79,800	-	-
2025	80,000	-	-
2026	80,100	-	-
2027	80,300	-	-
2028	80,400	-	-
Total	798,000	-	-
Difference from baseline		(798,000)	(798,000)

* Totals may not sum due to rounding.

Table 4.2c: Estimated Value of Methane Emissions Reductions of the 2016 Rule (No Action/Baseline), the 2018 Final Rule, and Alternative 2, Using the Interim Domestic SC-CH_4 ($ in 2016 millions)

	No Action/Baseline**		2018 Final Rule		Alternative 2	
	Interim Domestic SC-CH_4 (2016$)		Interim Domestic SC-CH_4 (2016$)		Interim Domestic SC-CH_4 (2016$)	
Year	7%	3%	7%	3%	7%	3%
2019	$8	$27	$0	$0	$0	$0
2020	$9	$28	$0	$0	$0	$0
2021	$9	$29	$0	$0	$0	$0
2022	$10	$30	$0	$0	$0	$0
2023	$10	$31	$0	$0	$0	$0
2024	$11	$32	$0	$0	$0	$0
2025	$11	$33	$0	$0	$0	$0
2026	$11	$34	$0	$0	$0	$0
2027	$12	$35	$0	$0	$0	$0
2028	$12	$36	$0	$0	$0	$0
NPV (7%)	$66.2		$0		$0	
NPV (3%)		$259		$0		$0
Difference from baseline (NPV7)			($66.2)		($66.2)	
Difference from baseline (NPV3)				($259)		($259)
Annualized difference (7%)			($9.42)		($9.42)	
Annualized difference (3%)				($30.4)		($30.4)

*Discounting done relative to 2018.

**Social benefits calculated as described in this RIA and not as presented in the 2016 RIA.

4.3 Net Benefits

The BLM analyzed the costs, benefits, and net benefits of the 2016 rule (no action/baseline) and determined that the 2016 rule would generate negative net benefits when implemented. The 2018 final rule is estimated to result in positive net benefits, relative to the baseline, meaning that the reduction of compliance costs would exceed the forgone cost savings from unrecovered natural gas and the value of the forgone methane emissions reductions. Tables 4.3a and 4.3b show the estimated net benefits of the 2016 rule, 2018 final rule, and Alternative 2, in detail.

Negative Net Benefits

No Action Alternative / Baseline: Leaving the 2016 rule intact would have resulted in estimated negative net benefits, or net costs. Over the 10-year evaluation period (2019-2028), we estimate total net benefits of the 2016 rule to be -\$736 million to -\$1.011 billion (NPV and interim domestic SC-CH_4 using a 7% discount rate) or -\$722 million to -\$1.086 billion (NPV and interim domestic SC-CH_4 using a 3% discount rate). Negative net benefits are net costs.

Net Benefits

Final Rule: The final rule will result in estimated positive net benefits. Over the 10-year evaluation period (2019-2028), we estimate total net benefits of \$734 million to \$1.009 billion (NPV and interim domestic SC-CH_4 using a 7% discount rate) or \$720 million to \$1.083 billion (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Alternative 2: Alternative 2 is also estimated to generate positive net benefits relative to the baseline, but fewer net benefits than the final rule. If the 2016 rule's gas-capture and metering/measuring requirements were retained, over the 10-year evaluation period (2019-2028), we estimate total net benefits of \$526 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or \$458 million (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Table 4.3a: Estimated Net Benefits of the 2016 Rule (No Action/Baseline), the 2018 Final Rule, and Alternative 2; NPV, Capital Costs Annualized, and Interim Domestic SC-CH_4 Based on a 7% Discount Rate; 10-Years (2019 – 2028) ($ in millions)

	No Action/Baseline		2018 Final Rule		Alternative 2	
Year	Lower estimate	Higher estimate	Lower estimate	Higher estimate	Lower estimate	Higher estimate
2019	($76)	($92)	($0)	($0)	$9	($7)
2020	($76)	($96)	($0)	($0)	$7	($14)
2021	($113)	($143)	($0)	($0)	($31)	($61)
2022	($174)	($207)	($0)	($0)	($92)	($126)
2023	($178)	($220)	($0)	($0)	($97)	($140)
2024	($130)	($177)	($0)	($0)	($51)	($99)
2025	($86)	($147)	($0)	($0)	($8)	($70)
2026	($96)	($165)	($0)	($0)	($19)	($88)
2027	($97)	($165)	($0)	($0)	($21)	($89)
2028	($100)	($167)	($0)	($0)	($25)	($92)
NPV (7%)	($736)	($1,011)	($2)	($2)	($211)	($486)
Difference from baseline (NPV7)			$734	$1,009	$526	$526
Annualized difference (7%)			$104	$144	$75	$75

*Discounting done relative to 2018. **Totals may not sum due to rounding.

Table 4.3b: Estimated Net Benefits of the 2016 Rule (No Action/Baseline), the 2018 Final Rule, and Alternative 2; NPV, Capital Costs Annualized, and Interim Domestic SC-CH_4 Based on a 3% Discount Rate; 10-Years (2019 – 2028) ($ in millions)

	No Action/Baseline		2018 Final Rule		Alternative 2	
Year	Lower estimate	Higher estimate	Lower estimate	Higher estimate	Lower estimate	Higher estimate
2019	($53)	($69)	($0)	($0)	$9	($6)
2020	($53)	($73)	($0)	($0)	$7	($13)
2021	($89)	($119)	($0)	($0)	($30)	($60)
2022	($149)	($183)	($0)	($0)	($91)	($125)
2023	($153)	($195)	($0)	($0)	($97)	($139)
2024	($104)	($152)	($0)	($0)	($50)	($98)
2025	($60)	($121)	($0)	($0)	($7)	($69)
2026	($69)	($138)	($0)	($0)	($19)	($87)
2027	($69)	($138)	($0)	($0)	($20)	($89)
2028	($72)	($139)	($0)	($0)	($24)	($91)
NPV (3%)	($722)	($1,086)	($3)	($3)	($264)	($628)
Difference from baseline (NPV3)			$720	$1,083	$458	$458
Annualized difference (3%)			$84	$127	$54	$54

*Discounting done relative to 2018. **Totals may not sum due to rounding.

4.4 Analysis of Individual Requirements Being Removed

We also examined the 2016 rule's equipment and operational requirements individually. Depending on the existing equipment at the wellsite, under the 2016 rule, the operator might have been required to do one or more of the following: Manage flaring from its oil wells in order to meet the gas-capture target; replace pneumatic controllers or pneumatic pumps; install equipment or otherwise intervene to avoid well purging associated with liquids unloading; retrofit existing storage tanks with a combustor or vapor recovery unit; and conduct a leak detection and repair program. The final rule removes these requirements.

Over the 10-year evaluation period (2019-2028), using a 7% discount rate for NPV and interim domestic SC-CH_4, we estimate that the pneumatic pump, storage tank, gas-capture-target, and LDAR provisions would have resulted in negative net benefits (or net costs) of about $3 million, $48 million, $174 million – $449 million, and $416 million, respectively. The pneumatic controller and liquids unloading requirements were estimated to generate positive net benefits of about $15 million and $16 million, respectively. We note that the 2018 final rule retains some of the liquids unloading requirements from the 2016 rule.

The results are similar using a 3% discount rate for NPV and interim domestic SC-CH_4. Over the 10-year evaluation period (2019-2028), we estimate that the storage tank, LDAR, and gas-capture-target provisions would have resulted in negative net benefits (or net costs) of about $45 million, $429 million, and $224 million – $588 million, respectively. The pneumatic controller, pneumatic pump, and liquids unloading requirements were estimated to generate positive net benefits of about $40 million, $29 million, and $61 million, respectively. Again, we note that the 2018 final rule retains some of the liquids unloading requirements from the 2016 rule. Please reference Table 4.4.

Pneumatic Controller Requirements

The BLM's analysis indicates that there are positive net benefits associated with the 2016 rule's pneumatic controller requirements and that the cost savings alone would exceed the compliance costs. As shown in Table 4.4, the present value of net benefits are estimated to be about $15 million over 10 years, with an annualized value of $2.12 million (see 7% discount rate case). Considering the compliance costs and cost savings alone, the requirements are estimated to generate net cost savings that exceed the compliance costs by $8 million over 10 years, with an annualized value of $1.16 million. The BLM notes that low-bleed controllers are common in the industry, reportedly making up 88% of the total continuous pneumatic controllers in operation.[50]

The BLM believes that, given the high prevalence of low-bleed continuous controller use in the industry, it is reasonable to assume that the remaining high-bleed continuous controllers are likely to be on wells that (1) have a functional need for their use or (2) have lower-than-average production or are marginal. If the well is low producing or marginal, then the potential cost

[50] According to data available in the EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2016. See Annex 3 Methodological Descriptions for Additional Source or Sink Categories at Table 3.5-5: Activity Data for Petroleum Systems Sources, for All Years and Table 3.6-7: Activity Data for Natural Gas Systems Sources, for All Years.

savings from a low-bleed pneumatic controller replacement on these wells should be lower than that assumed in this analysis. Given this concern and the small magnitude of the positive annualized values, in addition to other policy concerns described in the preamble to the final rule, the BLM believes that it is appropriate to rescind the 2016 rule's pneumatic controller requirements.

Liquids Unloading Requirements

The BLM's analysis also indicates that there are positive net benefits associated with the 2016 rule's liquids unloading requirements and that the cost savings alone would exceed the compliance costs. As shown in Table 4.4, the present value of net benefits are estimated to be about $16 million over 10 years, with an annualized value of $2.22 million (see 7% discount rate case). Considering the compliance costs and cost savings alone, the requirements are estimated to generate net cost savings that exceed the compliance costs by $2.1 million over 10 years, with an annualized value of $0.31 million.

We discuss the issues surrounding the liquids unloading baseline assumptions in Section 3.1 of this RIA. Although, for the purpose of consistency, the BLM has maintained the 2016 RIA's assumption that the 2016 rule's requirements would have compelled operators to install plunger lifts, the BLM continues to believe, for the reasons stated in the 2016 RIA, that the resulting estimates likely overstate the impact of the 2016 rule's liquids unloading requirements. In Section 7.3.2, the BLM has presented the estimated impacts of the 2018 final rule with an alternate baseline, where the 2016 rule would not have compelled the installation of plunger lifts.

LDAR Requirements

In the RIA for the 2016 rule, the BLM examined the impacts of a range of alternative approaches to LDAR. For all of the alternatives examined, the compliance costs greatly outweighed cost savings (i.e., the value of the gas conserved). See Section 3.2.1 of this RIA for a larger discussion of these results.

Table 4.4: Estimated Compliance Costs, Cost Savings, Interim Domestic SC-CH4, and Net Benefits for Equipment Requirements in the 2016 Rule (No Action/Baseline) that are Removed by the Final Rule; 10-Years (2019 – 2028) ($ in million)

NPV and Interim Domestic SC-CH4 Using a 7% Discount Rate				
Requirement	**PV Compliance Costs**	**PV Cost Savings**	**PV Interim Domestic SC-CH4 (2016$)**	**Net PV Benefits**
Gas-Capture Target (low)	$556	$381	$0.0	($174)
Gas-Capture Target (high)	$831	$381	$0.0	($449)
Pneumatic Controllers	$12.2	$20.4	$6.72	$14.9
Pneumatic Pumps	$28.5	$15.2	$10.0	($3.24)
Liquids Unloading	$38.5	$40.6	$13.4	$15.6
Storage Tanks	$51.2	$0.84	$2.65	($47.7)
LDAR	$550	$101	$33.4	($416)
Annualized Values (7%)				
Gas-Capture Target (low)	$79.1	$54.3	$0.0	($24.8)
Gas-Capture Target (high)	$118	$54.3	$0.0	($63.9)
Pneumatic Controllers	$1.74	$2.90	$0.956	$2.12
Pneumatic Pumps	$4.06	$2.17	$1.42	($0.46)
Liquids Unloading	$5.47	$5.78	$1.91	$2.22
Storage Tanks	$7.29	$0.120	$0.377	($6.80)
LDAR	$78.4	$14.4	$4.75	($59.2)
NPV and Interim Domestic SC-CH4 Using a 3% Discount Rate				
Requirement	**PV Compliance Costs**	**PV Cost Savings**	**PV Interim Domestic SC-CH4 (2016$)**	**Net PV Benefits**
Gas-Capture Target (low)	$731	$507	$0.0	($224)
Gas-Capture Target (high)	$1,095	$507	$0.0	($588)
Pneumatic Controllers	$12.7	$25.9	$26.3	$39.5
Pneumatic Pumps	$29.6	$19.4	$39.1	$28.9
Liquids Unloading	$43.9	$51.8	$52.7	$60.7
Storage Tanks	$56.0	$1.07	$10.4	($44.6)
LDAR	$688	$128	$131	($429)
Annualized Values (3%)				
Gas-Capture Target (low)	$85.7	$59.5	$0.0	($26.2)
Gas-Capture Target (high)	$128	$59.5	$0.0	($68.9)
Pneumatic Controllers	$1.49	$3.04	$3.08	$4.63
Pneumatic Pumps	$3.47	$2.27	$4.58	$3.39
Liquids Unloading	$5.14	$6.08	$6.18	$7.12
Storage Tanks	$6.57	$0.13	$1.21	($5.23)
LDAR	$80.7	$15.0	$15.3	($50.3)

*Discounting done relative to 2018.
**Totals may not sum due to rounding.

4.5 Distributional Impacts

4.5.1 Energy Systems

The final rule is expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases. However, the relative changes in production when compared to nation-wide production are expected to be small. The BLM does not expect that the final rule will significantly impact the price, supply, or distribution of energy.

In the RIA for the 2016 rule, the BLM estimated that that rule's gas-capture requirements would have likely forced operators to curtail a certain amount of oil production and potentially a certain amount of natural gas production.

Table 4.4a shows the estimated incremental production for the 2016 rule (no action/baseline), the 2018 final rule, and alternative 2.

No Action/Baseline: Leaving the 2016 rule intact would result in estimated incremental changes in crude oil and natural gas production. Over the 10-year evaluation period (2019-2028), we estimate that 18.4 million barrels of crude oil and 22.7 Bcf of natural gas would be deferred. However, we also estimate that there would be 299 Bcf of additional natural gas production that would have been brought to market rather than being vented or flared.

2018 Final Rule: The final rule will reverse the estimated incremental changes in crude oil and natural gas production associated with the 2016 rule. Over the 10-year evaluation period (2019-2028), we estimate that 18.4 million barrels of crude oil and 22.7 Bcf of natural gas will no longer be deferred (as it would have been under the 2016 rule). However, we also estimate that with the final rule, there will be 299 Bcf of forgone natural gas production (that would have been produced and sold under the 2016 rule).

For context, we note the share of the total U.S. production in 2015 that the incremental changes in production will represent. The per-year average of the estimated crude oil volume that will no longer be deferred represents 0.058% of the total U.S. crude oil production in 2015. The per-year average of the estimated natural gas volume that will no longer be deferred represents 0.008% of the total U.S. natural gas production in 2015. The per-year average of the estimated forgone natural gas production represents 0.109% of the total U.S. natural gas production in 2015.

Alternative 2: For Alternative 2, over the 10-year evaluation period (2019-2028), we estimate no change from the baseline in the amount of crude oil and natural gas crude oil production deferred and 91.6 Bcf of forgone natural gas production. For context, we note the share of the total U.S. production in 2015 that the incremental changes in production represent. The per-year average of the estimated forgone natural gas production represents 0.034% of the total U.S. natural gas production in 2015.

Table 4.5a: Estimated Incremental Production, 2016 Rule (No Action/Baseline), 2018 Final Rule, and Alternative 2 (Crude Oil in MMbbl; Natural Gas in Bcf)

	No Action/Baseline			2018 Final Rule			Alternative 2		
Year	**Crude Oil Deferred (MMbbl)**	**Natural Gas Deferred (Bcf)**	**Natural Gas Produced (Bcf)**	**Crude Oil Deferred (MMbbl)**	**Natural Gas Deferred (Bcf)**	**Natural Gas Produced (Bcf)**	**Crude Oil Deferred (MMbbl)**	**Natural Gas Deferred (Bcf)**	**Natural Gas Produced (Bcf)**
2019	0.09	0.39	16.3	0.00	0.00	0.00	0.09	0.39	7.23
2020	0.26	1.07	18.3	0.00	0.00	0.00	0.26	1.07	9.20
2021	1.46	2.63	22.9	0.00	0.00	0.00	1.46	2.63	13.8
2022	2.97	4.26	24.4	0.00	0.00	0.00	2.97	4.26	15.3
2023	3.24	3.83	28.3	0.00	0.00	0.00	3.24	3.83	19.1
2024	2.30	2.78	30.8	0.00	0.00	0.00	2.30	2.78	21.7
2025	1.68	1.72	37.1	0.00	0.00	0.00	1.68	1.72	27.9
2026	2.12	1.98	40.5	0.00	0.00	0.00	2.12	1.98	31.2
2027	2.15	2.02	40.4	0.00	0.00	0.00	2.15	2.02	31.2
2028	2.15	2.02	39.7	0.00	0.00	0.00	2.15	2.02	30.4
Total	18.4	22.7	299	0.00	0.00	0.00	18.4	22.7	207
Difference from baseline				-18.4	-22.7	-299	0.00	0.00	-91.6
Per-year average as a percent of the total U.S. production in 2015				-0.058%	-0.008%	-0.109%	0.000%	0.000%	-0.034%

*Totals may not sum due to rounding.

4.5.2 Royalty Impacts

The 2016 rule, when fully implemented, would have been expected to impact the production of crude oil and natural gas from Federal and Indian oil and gas leases. In the RIA for the 2016 rule, the BLM estimated that the requirements would have generated additional natural-gas production, but that substantial volumes of crude oil production would have been deferred or shifted to the future. The BLM concluded that the 2016 rule would have generated overall additional royalties, with the royalty gains from the conserved natural gas outweighing the value of the royalty losses from crude oil production (and some associated gas) being deferred into the future.[51]

The RIA for the 2016 rule made several important assumptions that were not quantitatively analyzed that could change the magnitude of royalties. The assumptions included: (1) No marginal or low-production wells would be prematurely abandoned; (2) No reservoirs would be damaged as a result of temporary shut-in; and (3) No drilling activity would shift to non-Federal lands. If any of these assumptions did not hold, the amount of royalty gains under the 2016 rule would have been lower than estimated.

This final rule, which reverses most of the 2016 rule's provisions, is expected to reverse the estimated royalty impacts of the 2016 rule. Although noted here, this formulation does not account for the possibility that the reduction in compliance burdens might spur additional production on Federal and Indian lands and have a positive impact on royalties.

As it did in the 2016 RIA, the BLM calculated the royalty impacts of this 2018 final rule using the following methodology:

- Baseline: For requirements that would result in incremental gas production, we calculate the additional royalties based on that production. When considering the deferment of production that could result from the 2016 rule's flaring limit, we calculate the incremental royalty as the difference in the present value of the royalty received ten years later and the value of the royalty that would have been received now or absent the deferment. For incremental gas production that would occur only due to estimated oil production deferment, the royalty of the value that would be received now is $0, and so the difference is therefore the present value of the royalty received in the future. This methodology is described in the 2016 RIA at 117. We note that the change in royalty impacts described in the 2016 RIA are due to the update in commodity prices and the fact that, under the 2018 rule baseline, there would be no phase-in period for the gas capture requirements (see Section 3.1 discussion).
- 2018 Final Rule: We reverse the estimated royalty impacts described in the baseline. The incremental gas production and additional royalties under the baseline would be forgone under the 2018 final rule. The deferred production and deferred royalties under the baseline would no longer occur under the 2018 final rule.
- Alternative 2: A portion of the estimated royalty impacts described in the baseline would be reversed, i.e., those associated with the equipment requirements. Meanwhile, the

[51] The royalty value of the deferred crude oil and natural gas production was calculated as 12.5% of the difference between the current year value of the volume being deferred and the present value of the deferred volume assuming it is produced 10 years later.

deferred production and deferred royalties under the baseline would occur since Alternative 2 would have maintained the gas capture requirements.

We note that royalty impacts are presented separately from the costs, benefits, and net benefits, in Sections 4.1 – 4.3 of this RIA. Royalty payments are recurring income to Federal or tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important but sometimes difficult problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.[52]

Incremental Royalty

No Action/Baseline: Leaving the 2016 rule intact would have resulted in estimated incremental royalty to the Federal Government, tribal governments, States, and private landowners. Over the 10-year evaluation period (2019-2028), we estimate total additional royalty of $28.3 million (NPV using a 7% discount rate) or $79.1 million (NPV using a 3% discount rate). As noted above, BLM has re-estimated incremental royalty at a lower amount compared to the original estimation for the 2016 rule.

The difference in the re-estimate from the original is owed to the following: the BLM corrected a calculation error in the 2016 RIA, there would no longer be a phase-in period for the gas capture requirements (as was accounted for in the 2016 RIA), and the 2018 RIA accounts for the EIA's current crude oil and natural gas price projections. See Section 3.1 for an explanation of these factors. See Tables 4.5b and 4.5c for accounting of the baseline royalty estimates.

[52] OMB Circular A-4 "Regulatory Analysis." September 17, 2003. Available at https://www.whitehouse.gov/omb/circulars_a004_a-4/.

ed Incremental Royalty with the 2016 Rule (No Action/Baseline) (Deferred Royalty Calculated Using a 2019 – 2028 ($ in millions)

nt nts	Gas Capture Requirements			Equipment Requirements	Gas Capture Requirements			
al on	Incremental Gas Production (Bcf)	Deferred Oil Production (MMbbl)	Deferred Gas Production (Bcf)	Incremental Gas Royalty ($MM)	Incremental Gas Royalty ($MM)	Difference in PV of Deferred Oil Royalty ($MM)	Difference in PV of Deferred Gas Royalty ($MM)	Total Incremental Royalty (Baseline)
.02	7.23	0.09	0.39	$2.96	$2.38	-$0.09	$0.08	5.33
.05	9.20	0.26	1.07	$3.23	$3.28	-$0.69	$0.22	6.05
.08	13.85	1.46	2.63	$3.21	$4.90	-$4.96	$0.55	3.71
.12	15.33	2.97	4.26	$3.26	$5.48	-$11.03	$0.90	-1.39
.15	19.15	3.24	3.83	$3.39	$7.09	-$12.75	$0.80	-1.47
.18	21.67	2.30	2.78	$3.50	$8.27	-$9.16	$0.58	3.19
.21	27.87	1.68	1.72	$3.63	$10.98	-$7.03	$0.36	7.95
.24	31.23	2.12	1.98	$3.68	$12.44	-$9.04	$0.42	7.50
.27	31.16	2.15	2.02	$3.74	$12.57	-$9.23	$0.43	7.52
.30	30.35	2.15	2.02	$3.77	$12.30	-$9.43	$0.44	7.08
							NPV (7%)	$28.3
							Annualized difference (7%)	$4.03

Table 4.5c: Estimated Incremental Royalty with the 2016 Rule (No Action/Baseline) (Deferred Royalty Calculated Using a 3% Discount Rate), 2019 – 2028 ($ in millions)

	Equipment Requirements	Gas Capture Requirements			Equipment Requirements	Gas Capture Requirements			
Year	Incremental Gas Production (Bcf)	Incremental Gas Production (Bcf)	Deferred Oil Production (MMbbl)	Deferred Gas Production (Bcf)	Incremental Gas Royalty ($MM)	Incremental Gas Royalty ($MM)	Difference in PV of Deferred Oil Royalty ($MM)	Difference in PV of Deferred Gas Royalty ($MM)	Total Incremental Royalty (Baseline)
2019	9.02	7.23	0.09	0.39	$2.96	$2.38	$0.14	$0.12	5.60
2020	9.05	9.20	0.26	1.07	$3.23	$3.28	-$0.02	$0.33	6.83
2021	9.08	13.85	1.46	2.63	$3.21	$4.90	-$1.15	$0.81	7.77
2022	9.12	15.33	2.97	4.26	$3.26	$5.48	-$3.18	$1.31	6.87
2023	9.15	19.15	3.24	3.83	$3.39	$7.09	-$4.06	$1.18	7.61
2024	9.18	21.67	2.30	2.78	$3.50	$8.27	-$2.93	$0.85	9.69
2025	9.21	27.87	1.68	1.72	$3.63	$10.98	-$2.40	$0.53	12.74
2026	9.24	31.23	2.12	1.98	$3.68	$12.44	-$3.16	$0.62	13.58
2027	9.27	31.16	2.15	2.02	$3.74	$12.57	-$3.12	$0.64	13.83
2028	9.30	30.35	2.15	2.02	$3.77	$12.30	-$3.26	$0.65	13.46
								NPV (3%)	$79.1
								Annualized difference (3%)	$9.27

Forgone Royalty

2018 Final Rule: The final rule is expected to result in forgone royalty payments to the Federal Government, tribal governments, States, and private landowners. Over the 10-year evaluation period (2019-2028), we estimate total forgone royalty payments of $28.3 million (NPV using a 7% discount rate) or $79.1 million (NPV using a 3% discount rate).

Alternative 2: For Alternative 2, we also estimate forgone royalty payments, relative to the baseline. Over the 10-year evaluation period (2019-2028), we estimate total forgone royalty payments (from the baseline) of $23.8 million (NPV using a 7% discount rate) or $35.3 million (NPV using a 3% discount rate). See Tables 4.5d and 4.5e, below.

Table 4.5d: Estimated Incremental Royalty with the 2016 Rule (No Action/Baseline) (Deferred Royalty Calculated Using a 7% Discount Rate), 2018 Final Rule, and Alternative 2, 2019 – 2028 ($ in millions)

Year	No Action/Baseline	2018 Final Rule	Alternative 2
2019	$5.33	$0.00	$2.37
2020	$6.05	$0.00	$2.82
2021	$3.71	$0.00	$0.49
2022	($1.39)	$0.00	($4.65)
2023	($1.47)	$0.00	($4.86)
2024	$3.19	$0.00	($0.31)
2025	$7.95	$0.00	$4.32
2026	$7.50	$0.00	$3.82
2027	$7.52	$0.00	$3.78
2028	$7.08	$0.00	$3.31
NPV (7%)	$28.3	$0.00	$4.5
Difference from baseline (NPV7)		($28.3)	($23.8)
Annualized difference (7%)		($4.03)	($3.39)

*Discounting done relative to 2018.

Table 4.5e: Estimated Incremental Royalty with the 2016 Rule (No Action/Baseline) (Deferred Royalty Calculated Using a 3% Discount Rate), 2018 Final Rule, and Alternative 2, 2019 – 2028 ($ in millions)

Year	No Action/Baseline	2018 Final Rule	Alternative 2
2019	$5.60	$0.00	$2.64
2020	$6.83	$0.00	$3.59
2021	$7.77	$0.00	$4.56
2022	$6.87	$0.00	$3.61
2023	$7.61	$0.00	$4.22
2024	$9.69	$0.00	$6.19
2025	$12.7	$0.00	$9.11
2026	$13.6	$0.00	$9.90
2027	$13.8	$0.00	$10.1
2028	$13.5	$0.00	$9.69
NPV (3%)	$79.1	$0.00	$43.8
Difference from baseline (NPV3)		($79.1)	($35.3)
Annualized difference (3%)		($9.27)	($4.14)

*Discounting done relative to 2018.

4.5.3 Employment Impacts

E.O. 13563 reaffirms the principles established in E.O. 12866, but calls for additional consideration of the regulatory impact on employment. It states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

In the RIA for the 2016 rule, the BLM concluded that the requirements were not expected to impact the employment within the oil and gas extraction, drilling oil and gas wells, and support activities industries, in any material way. This determination was based on several reasons. First, the estimated incremental gas production represented only a small fraction of the U.S. natural gas production volumes. Second, the estimated compliance costs represented only a small fraction of the annual net incomes of companies likely to be impacted. Third, for those operations that would have been impacted, to the extent that the compliance costs would force the operator to shut in production, the 2016 rule had provisions that would have allowed operators to seek exemptions from compliance (or to seek approval for an alternate LDAR program). Based on these factors, the BLM determined that the 2016 rule would not have altered the investment or employment decisions of firms or significantly adversely impact employment. The RIA also noted that the requirements would have necessitated the one-time installation or replacement of equipment and the ongoing implementation of an LDAR program, both of which would have required expenditures.

We do not believe that this final rule will substantially alter the investment or employment decisions of firms. By removing or revising the requirements of the 2016 rule, the BLM will alleviate the associated compliance burdens on operators. While we do not believe that the cost savings in themselves will be substantial enough to substantially alter the investment or employment decisions of firms, we also recognize that there may be a small positive impact on investment and employment due to the reduction in compliance burdens if the output effects dominate. The magnitude of the reductions will be relatively small, but could carry competitiveness impacts, specifically on marginal wells on Federal lands. However, the investment and employment necessary to comply with the 2016 rule would not be needed. In sum, the effect on investment and employment of this rule remains unknown.

4.5.4 Small Business Impacts

The BLM reviewed the SBA size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau. We conclude that small entities represent the overwhelming majority of entities operating in the onshore crude oil and natural gas extraction industry and, therefore, the final rule will impact a substantial number of small entities.

To examine the economic impact of the rule on small entities, the BLM performed a screening analysis on a sample of potentially affected small entities, comparing the reduction of compliance costs to entity profit margins.

The BLM identified up to 1,828 entities that operate Federal and Indian leases and recognized that the overwhelming majority of these entities are small business, as defined by the SBA. We estimated the potential reduction in compliance costs less the forgone costs savings to be about $72,000 per entity per year.

We used existing BLM information and research concerning firms that have recently completed Federal and Indian wells and the financial and employment information on a sample of these firms, as available in company annual report filings with the Securities and Exchange Commission (SEC). From the original list of companies, we identified 55 company filings. Of those companies, 33 were small businesses, as defined by the SBA.

From data in the companies' 10-K filings to the SEC, the BLM was able to calculate the companies' profit margins[53] for the years 2012, 2013, and 2014. We then calculated a profit margin figure for each company when subject to the average annual reduction in compliance costs associated with this proposed rule. For these small companies, the estimated per-entity reduction in compliance costs would result in an average increase in profit margin of 0.20 percentage points (based on the 2014 company data).[54]

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[53] The profit margin was calculated by dividing the net income by the total revenue as reported in the companies' 10-K filings.

[54] Since this analysis examines the profit margins of businesses that are more likely to be public, it is biased towards small businesses with larger revenue. Therefore, we might anticipate that the reduction in compliance costs expected with this rule will represent a larger increase in the profit margins for small businesses than that shown. In addition, average commodity price in 2014 was higher than subsequent years; therefore, the result in profit margin may not be representative of the increase in profit margin as a result of the updated rulemaking. Even if that positive impact is greater, it is unlikely to achieve the level of being significant.

4.5.5 Impacts on Tribal Lands

The final rule applies to oil and gas operations on both Federal and Indian leases. From 2013 to 2015, BLM's Automated Fluid Minerals Support System indicates that wells on Indian leases accounted for roughly 15% of the oil wells and 11% of the gas wells on Federal and Indian lands. Based on the results described in sections 4.1 to 4.4.4 of this RIA, we generally expect that the impacts associated with operations on Indian leases may be determined by scaling down the total impacts by the share of oil wells on Indian lands and the share of gas wells on Indian lands. As such, we expect the impacts of the final rule on tribal lands to be between 11% and 15% of those levels described in sections 4.1 to 4.4.4.

Estimated reductions in compliance costs associated with operations on Indian leases. Over the 10-year evaluation period (2019-2028), we estimate a total reduction in compliance costs of up to \$204 million – \$245 million (NPV using a 7% discount rate) or up to \$257 million – \$311 million (NPV using a 3% discount rate).

Estimated reduction in benefits associated with operations on Indian leases. Over the 10-year evaluation period (2019-2028), we estimate a total forgone cost savings from the recovery of natural gas of up to \$84 million (NPV using a 7% discount rate) or \$110 million (NPV using a 3% discount rate) and forgone methane emissions reductions valued at up to \$10 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or up to \$39 million (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Estimated net benefits associated with operations on Indian leases. We estimate positive net benefits relative to the baseline, meaning that the reduction of compliance costs will exceed the reduction in cost savings and the change in the value of emissions. Over the 10-year evaluation period (2019-2028), we estimate net benefits of \$110 million – \$151 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or \$108 million – \$163 million (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Incremental production associated with operations on Indian leases. Over the 10-year evaluation period (2019-2028), we estimate that 2.76 million barrels of crude oil and 3.4 Bcf of natural gas will no longer be deferred (as it would have been under the 2016 rule). However, we also estimate that with the final rule, there will be 45 Bcf of forgone natural gas production (that would have been produced and sold rather than vented or flared under the 2016 rule).

Incremental royalty associated with operations on Indian leases. We estimate forgone royalty payments from the baseline. Over the 10-year evaluation period (2019-2028), we estimate total forgone royalty payments of \$4.25 million (NPV using a 7% discount rate) or \$11.9 million (NPV using a 3% discount rate). This RIA does not measure the potential positive royalty impacts that would occur if the alleviation of compliance burdens spurs additional production on Indian lands.

4.5.6 Concerns over Marginal Wells and Potential Shut-In or Premature Abandonment

The Interstate Oil and Gas Compact Commission (IOGCC) published a report in 2015 detailing the contributions of marginal wells to the nation's oil and gas production and economic activity.[55] According to the IOGCC, about 69.1 percent and 75.9 percent of the nation's operating oil and gas wells, respectively, are marginal (IOGCC 2015 at 22). The IOGCC defines a marginal well as "a well that produces 10 barrels of oil or 60 Mcf of natural gas per day or less" (IOGCC 2015 at 2).[56] The U.S. Energy Information Administration (EIA) reported that, in 2016, roughly 62.7 percent of oil wells produced less than or equal to 4 barrels of oil equivalent (BOE) per day and 76.4 percent of oil wells produced less than or equal to 10 BOE/day. For gas wells, EIA reported that roughly 54.3 percent produced less than or equal to 4 BOE/day and 71.6 percent less than or equal to 10 BOE/day. For both oil and gas wells, EIA estimates that 73.7 percent of all wells produce less than 10 BOE/day.[57] Applying these estimates to the overall number of BLM-administered wells indicates that about 69,000 wells producing Federal and/or Indian oil and gas are marginal.[58]

The RIA for the 2016 rule recognized that not all existing wells would be able to economically support the additional costs posed by the rule's requirements and that these costs could cause the operator to prematurely abandon the well. The 2016 RIA then explained that the BLM did not think the 2016 rule would have forced operators to prematurely abandon wells, since the rule contained exemption clauses to remove or reduce requirements where compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease. The 2016 rule contained such provisions for its gas-capture-percentage, pneumatic-equipment, storage-vessel, and LDAR requirements. Notably, the 2016 rule did not allow for full exemptions from the LDAR requirements. Instead it allowed the operator to seek approval for an alternate and less-stringent program, presumably to allow the operator to continue operations without premature abandonment.

Since overlapping EPA NSPS OOOO and OOOOa regulate new, modified, or reconstructed sources, the 2016 rule's LDAR, pneumatic-controller, and pneumatic-pump requirements would have practically impacted only existing wells, which are more likely to be marginal, since production rates decline over time. In addition, the 2016 rule's liquids unloading requirements

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[55] IOGCC, "Marginal Wells: Fuel for Economic Growth. 2015 Report." Available on the web at http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/MarginalWell-2015.pdf.

[56] By other definitions, marginal or stripper wells might include those with production of up to 15 barrels of oil or 90 Mcf of natural gas per day or less. The U.S. Energy Information Administration (EIA) reported that, in 2009, roughly 78.7 percent of oil wells produced less than or equal to 10 barrels of oil equivalent (BOE) per day and 85.4 percent of oil wells produced less than or equal to 15 BOE/day. For gas wells, EIA reported that roughly 64.5 percent produced less than or equal to 10 BOE/day and 73.3 percent less than or equal to 15 BOE/day. EIA, "United States Total 2009: Distribution of Wells by Production Rate Bracket." December 2010. Available on the web at https://www.eia.gov/naturalgas/archive/petrosystem/us_table.html.

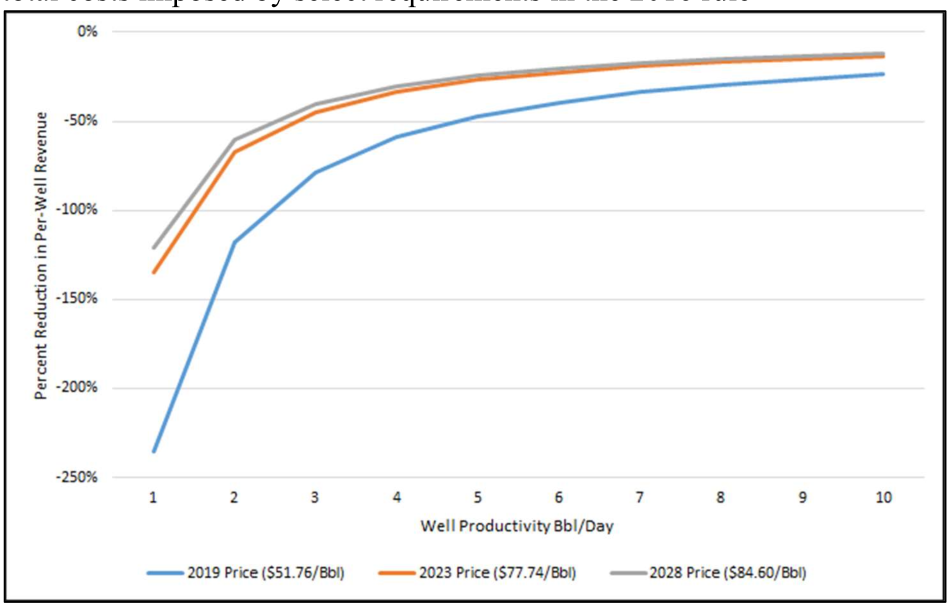
[57] EIA, "The Distribution of U.S. Oil and Natural Gas Wells by Production Rate." December 2017. Available on the web at https://www.eia.gov/petroleum/wells/. See Appendix B: Selected summary tables.

[58] BLM oil and gas statistics. Available on the web at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics.

would have posed a particular burden on declining gas wells, as liquids unloading is not necessary for more productive wells with sufficient reservoir pressure.[59]

To illustrate the 2016 rule's impact on the economic viability of marginal oil and gas wells, Figures 4.5a through 4.5d display the per-well reduction in revenue from the costs imposed by the requirements in the 2016 rule. We calculate the reduction in revenue using both total and annualized costs and for three different price points.[60] The per-well revenue values are the product of estimated annual production and annual average prices less royalty payments and lifting costs.[61] This analysis does explicitly include resource recovery from the 2016 rule capture requirements. It is possible that the capture requirements would increase marketable production and subsequent revenue, but the BLM expects the recovery to be less for marginal wells given the low producing nature. Under 2019 prices, the estimated revenue reduction for marginal oil wells due to compliance with the 2016 rule ranges from 24% for wells producing 10 bbl/day to 236% for wells producing 1 bbl/day. Revenue reductions on marginal gas wells range from 86% for wells producing 60 mcf/day to 1,037% for wells producing 5 mcf/day. These values are reduced when using annualized costs, however, the reductions in revenue are still substantial.

Figure 4.5a: Percent reduction in per-well revenue on marginal oil wells (Bbl/Day <= 10) from total costs imposed by select requirements in the 2016 rule



[59] We note that the storage vessel requirements, which impacting existing wells, are not expected to impact marginal wells due to the low production and relatively high VOC threshold.

[60] The forecasted 2019, 2023, and 2028 prices are from EIA's 2018 AEO (https://www.eia.gov/outlooks/aeo/). We use 98% and 75% of the oil and gas prices respectively to better reflect the actual prices that Federal wells receive. See the RIA for the 2016 rule for more information on these price reductions.

[61] Lifting costs (also called production costs) are the costs to operate and maintain wells and related equipment and facilities per barrel of oil equivalent (boe) of oil and gas produced by those facilities after the hydrocarbons have been found, acquired, and developed for production.

Figure 4.5b: Percent reduction in per-well revenue on marginal oil wells (Bbl/Day <= 10) from annualized costs imposed by select requirements in the 2016 rule

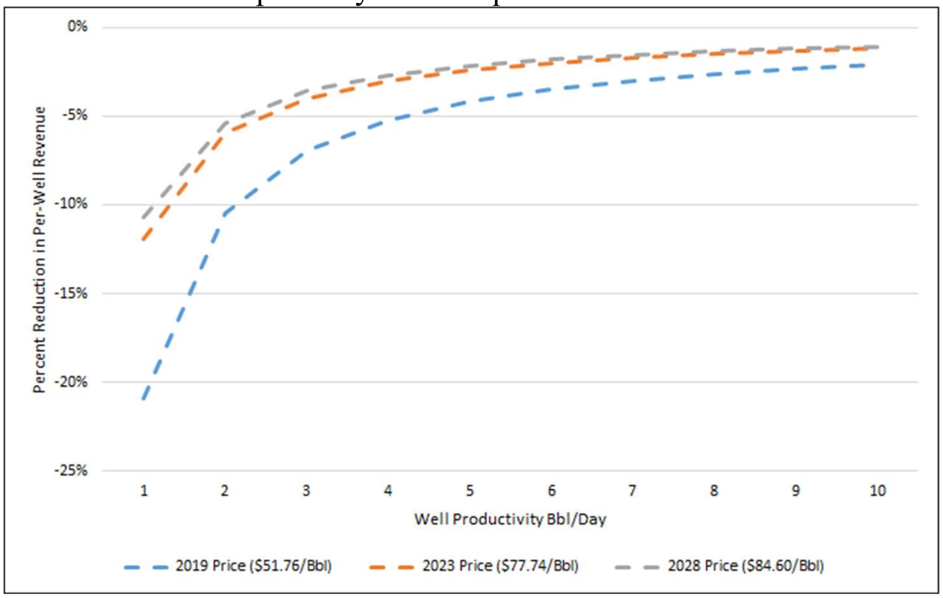


Figure 4.5c: Percent reduction in per-well revenue on marginal gas wells (Mcf/Day <= 60) from total costs imposed by select requirements in the 2016 rule

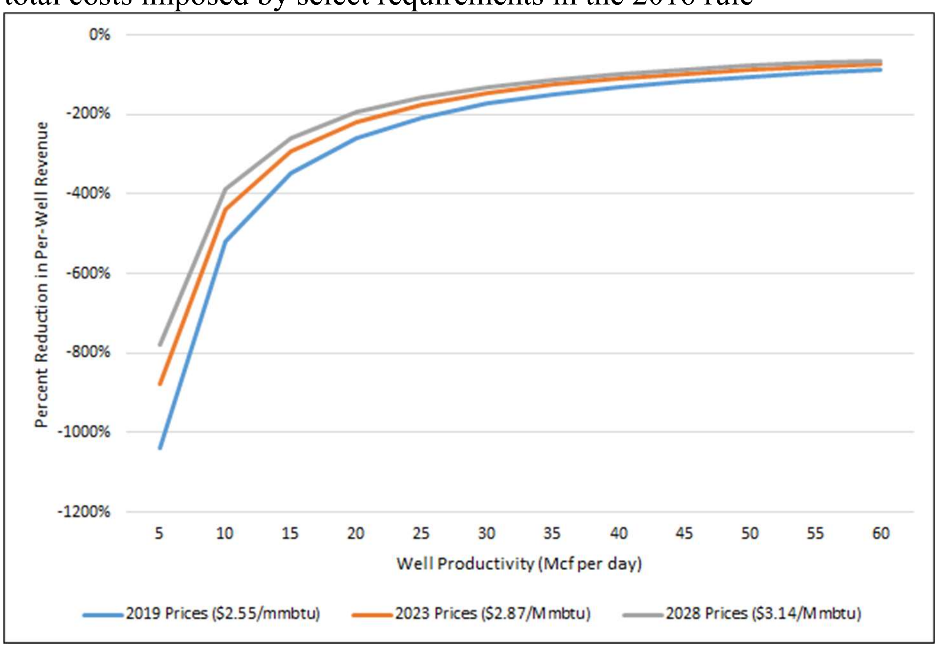
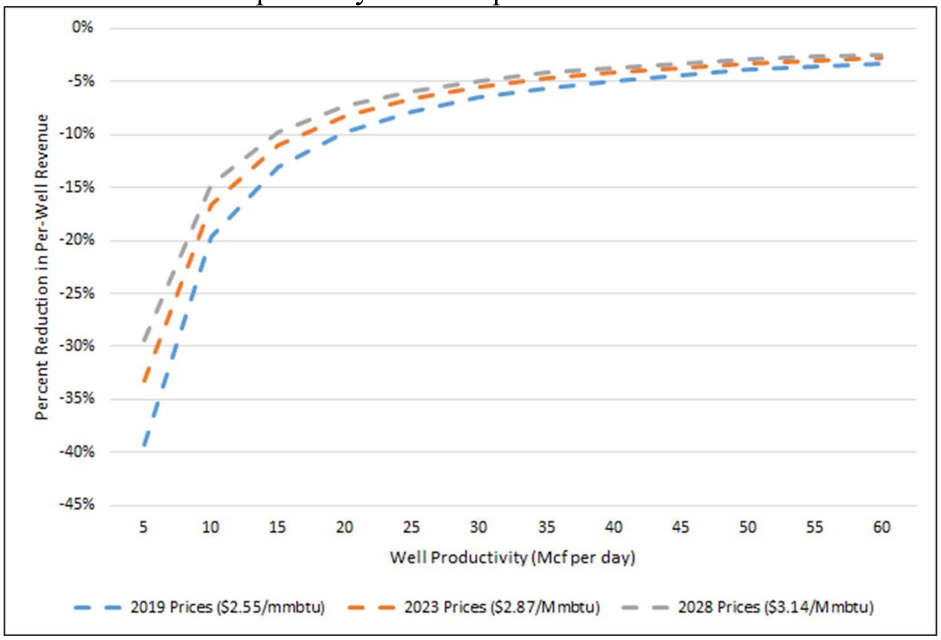


Figure 4.5d: Percent reduction in per-well revenue on marginal gas wells (Mcf/Day <= 60) from annualized costs imposed by select requirements in the 2016 rule



These estimates of the percentage revenue reduction for marginal wells indicate that the 2016 rule's requirements would have been particularly burdensome for the operators of marginal wells. Even the highest-producing marginal oil wells (10 bbl/day) stood to lose 24% of their revenues by complying with the 2016 rule's requirements. This indicates to the BLM that the operators of many marginal wells would have likely sought, and would have likely received, an exemption from the 2016 rule's requirements. (The BLM notes that compliance costs associated with the 2016 rule are only part of the total costs an operator faces, including State and Federal taxes, and reclamation costs.) Given the prevalence of marginal wells, the economic exemption process contained in the 2016 rule was likely to impose a substantial, and in many cases unnecessary, administrative burden on both the operators of marginal wells and the BLM.

The prospect of either shutting-in a marginal well or assuming unwarranted administrative burdens to avoid compliance costs potentially represented a substantial loss of income for companies operating marginal wells. In the 2016 RIA, the BLM used the underlying assumption that all operators of marginal wells needing exemptions from the various requirements would have applied for the exemptions and that those exemptions would have been granted to them. The 2016 RIA also assumed that all operators of marginal wells would have been able to absorb the costs associated with the LDAR program or an alternate program of lesser stringency. There is reason to believe this assumption is not appropriate, given the potential that operators of the lowest producing wells would not have been able to absorb the administrative burdens and/or LDAR compliance costs, and would have either temporarily shut-in or prematurely abandoned the wells.

Oil and gas production from marginal wells on Federal land provide a significant economic contribution to the national economy. To illustrate this, the BLM estimated the economic output associated with oil and gas production from marginal wells on Federal land in FY 2015 (Table 4.5.6).[62] Using components of the analysis presented in the IOGCC report, the BLM found that marginal oil and gas production on Federal land supported an estimated $2.9 billion in economic output in the national economy. To the extent that the 2016 rule would have adversely impacted production from marginal wells through premature shut-ins, this estimated economic output would have been jeopardized.

The values reported in Table 4.5.6 should not be equated to or described similarly as an analysis that measures net economic benefits. Economic output contributions track how expenditures from an event flow through the economy and does not provide insight into potential economic benefits and whether the expenditures lead to the enhancement of societal welfare. Therefore, these values are not included in the summation of net benefits associated with this rule.

Table 4.5.6: FY 2015 Estimated Economic Output Associated with Marginal Well Production on Federal Land ($ in millions)

BLM Oil	$1,407
Tribal Oil	$466
Federal Oil (BLM + tribal)	**$1,873**
BLM Natural Gas	$902
Tribal Gas	$91
Federal Natural Gas (BLM + tribal)	**$994**
Total DOI	**$2,867**

*Values may not sum due to rounding

[62] FY 2015 is the most recent year presented in the IOGCC report.

4.5.7 Sensitivity Analysis, Alternative Natural Gas Prices

In this section, we summarize the impacts of the rule using alternative natural gas prices. These results account for natural gas prices that are 89% of the EIA's projections. The basis for this assumption is an EIA analysis from 2002, which found that Henry Hub prices were, on average, about 11% higher than wellhead prices. See Section 7.3.1 for the full results using this price assumption.

Estimated reductions in compliance costs. The 2018 final rule will reduce compliance costs from the baseline. Over the 10-year evaluation period (2019-2028), we estimate a total reduction in compliance costs of $1.37 billion – $1.64 billion (NPV using a 7% discount rate) or $1.72 billion – $2.09 billion (NPV using a 3% discount rate). Using higher natural gas prices for this sensitivity analysis results in slightly higher compliance costs over a 10-year period, due to a slight increase in the cost of deferment.

Estimated reduction in benefits associated with operations. The final rule will result in forgone cost savings from natural gas recovery. Over the 10-year evaluation period (2019-2028), we estimate total forgone cost savings from natural gas recovery of $631 million (NPV using a 7% discount rate) or $829 million (NPV using a 3% discount rate). Using higher natural gas prices for this sensitivity analysis results in higher forgone cost savings over a 10-year period, due to the higher assumed value of the natural gas. The natural gas price assumptions do not affect the estimated forgone methane emissions reductions presented in Section 4.2. Over the 10-year evaluation period (2019-2028), we estimate total forgone methane emissions reductions from the baseline valued at $66 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or $259 million (NPV and interim domestic SC-CH_4 using a 3% discount rate).

Estimated net benefits associated with operations. The final rule will result in estimated positive net benefits. Over the 10-year evaluation period (2019-2028), we estimate total net benefits of $671 million to $946 million (NPV and interim domestic SC-CH_4 using a 7% discount rate) or $635 million to $999 million (NPV and interim domestic SC-CH_4 using a 3% discount rate). Using higher natural gas prices for this sensitivity analysis results in positive net benefits over a 10-year period. However, the net benefits are about $63 million to $85 million less, over a 10-year period, than the net benefits estimated in Section 4.3.

Incremental royalty associated with operations. The final rule is expected to result in forgone royalty payments to the Federal Government, tribal governments, States, and private landowners. Over the 10-year evaluation period (2019-2028), we estimate total forgone royalty payments of $42.0 million (NPV using a 7% discount rate) or $97.3 million (NPV using a 3% discount rate). Using higher natural gas prices for this sensitivity analysis results in higher forgone cost savings over a 10-year period, due to the higher assumed value of the natural gas. Using this natural gas price scenario, the forgone royalties are about $14 million to $18 million higher, over a 10-year period, than the forgone royalties estimated in Section 4.5.5.

4.5.8 Additional Considerations

In this section, we qualitatively discuss other potential impacts of the final rule.

Potential impact on new drilling on Federal lands. The RIA for the 2016 rule considered that potentially higher development costs for new operations on Federal and Indian lands could make these properties less desirable than non-Federal and non-tribal properties, and that, in response, operators might conceivably shift future activity away from Federal and Indian lands to non-Federal and non-Indian properties or, less conceivably, away from the affected areas or regions entirely. The RIA then explained why the BLM did not think that such a response would have occurred, citing industry preference to site development in areas with the capacity to transport all gas that is produced and the fact that control technologies are currently available and widely used by the industry.

This final rule alleviates almost all of the compliance burdens of the 2016 rule, thereby reducing the costs of developing new oil and gas resources on Federal and Indian lands. Therefore, we do not expect the previously stated concerns to be an issue for the final rule.

Impact on lease bids as a result of higher regulatory costs. The RIA for the 2016 rule also expressed the concern that any added and significant regulatory costs would have reduced the level of bonus bids that the Federal Government would have received for new Federal leases or the upfront payments that a tribal government would have received for its new leases. The BLM awards the rights to develop an oil and gas lease on Federal lands to the company that bids the highest amount at auction. Leases that do not receive bids may be acquired through a non-competitive process. The RIA then explained why the BLM did not think that such a response would have occurred, since it did not consider the compliance costs of the 2016 rule to be significant for new leases, explaining that EPA regulations addressed many of the requirements affecting new operations.

This final rule alleviates almost all of the compliance burdens of the 2016 rule, thereby reducing the costs of developing new oil and gas resources on Federal and Indian lands. Therefore, we do not expect the previously stated concerns to be an issue for this final rule.

Indirect economic impacts in regions where flaring would have been in excess of the limits. In general, economic impacts can be estimated at the direct, indirect, and induced levels. Direct impacts result from expenditures associated with the operations (or compliance with the regulation) and include, for example, labor, equipment, and capital. Indirect impacts result from the suppliers of the purchased goods and services used in the operations and hiring workers to deliver those goods and services. These “2nd round” impacts would not occur if not for the operations themselves. Induced impacts result from the employees of the operations and suppliers at a household level.

The RIA for the 2016 rule expressed concern that the requirements might have generated negative indirect or induced impacts if operators had chosen to reduce investment and thereby reduce transactions made with suppliers or service providers, particularly in regions where oil-well gas flaring is the highest and where the operator might not have achieved the gas-capture

targets. The BLM explained that several aspects of the 2016 rule were designed to account for ongoing State efforts, including the flexibility to issue variances upon a determination by the BLM that a State or tribal government's regulation meets or exceeds the requirements of BLM's respective provision(s).

This final rule alleviates the compliance burden of the 2016 rule with respect to the gas-capture requirements. Therefore, we do not expect the previously stated concerns to be an issue for the final rule.

Concerns that changes required under this rule would trigger permitting requirements. The RIA for the 2016 rule noted stakeholders' concerns that operators might have needed to obtain regulatory approvals, such as rights-of-way or Clean Air Act permits, for various actions required by the 2016 rule. For example, the 2016 rule might have required the operator to take action to "modify" a source, thus triggering EPA compliance requirements. Or, an operator might have needed to obtain new approvals for rights-of-way or supplement the pre-existing National Environmental Policy Act analysis to account for the additional environmental impacts from adding capture equipment to the site.

This final rule alleviates almost all of the compliance burdens of the 2016 rule, thereby eliminating any need for additional permitting requirements related to the 2016 rule's requirements. Therefore, we do not expect the previously stated concerns to be an issue for the final.

4.5.9 Additional Commenter Analyses

In this section we present and discuss alternative estimates of the costs and benefits to the final 2018 rule submitted by some commenters to further illustrate the uncertainty around the estimates presented in this RIA. The following analyses do not account for all of the alternative estimates submitted by commenters nor do they represent the full content of the individual submissions. Please refer to the response-to-comment document prepared for this rulemaking for other comment submissions and responses. The BLM did not incorporate any of these estimates into the final 2018 rule net benefit analysis.

API

The American Petroleum Institute (API) submitted comments generally in support of the final 2018 rule. Environmental Resources Management (ERM) and Earth System Sciences (ESS) reviewed the assumptions, calculations and analysis used in the 2018 RIA on behalf of API. The BLM appreciates the commenter's analysis, however, it was conducted using proprietary data and models and the BLM was unable to replicate the results. ERM reviewed the following specific areas:

- **LDAR inspection program.** The analysis states that the BLM underestimated the number of wells that would be subject to LDAR requirements, resulting in higher savings than estimated in the proposed 2018 RIA. The ERM and ESS analysis finds roughly 6,000 more wells that would be covered compared to the BLM's estimate. The two groups also find that the RIA underestimates compliance costs per well, while also overestimating gas recovered and sold per well. The analysis also states that this overestimate results in higher methane emission estimates and subsequent benefits associated with methane emissions reductions.
- **Flaring capture requirements.** This analysis is primarily focused on Alternative 2 of the proposed 2018 RIA. ERM uses a different set of assumptions and model to attempt to better reflect uncertainty in costs, capacity and activity. ERM estimates that implementing Alternative 2 would cost the industry an average of $84 million/year, $38 million more than estimated in the 2018 RIA.
- **Foregone value of the reductions in emissions.** The ERM analysis states that low discount rates have unexplored and potentially counter-intuitive implications. ERM estimates 45,246 tons in annual emissions reductions compared to 177,222 in the 2018 RIA.

The API also submitted a presentation to OMB during its E.O. 12866 Review of the BLM's final rule.[63] The API made several assertions concerning the RIA that the BLM prepared for the proposed rule, including:

1. The BLM inverted the methane to VOC ratio used to calculate VOC reductions for liquids unloading and pneumatic controllers. API asserted that the BLM "assumed that: 1

[63] API "Calculation error: VOC to Methane Ratio, Liquids Unloading," Presentation provided to OMB on July 18, 2018.

tpy VOC = 0.278 tpy methane" (RIA at 55 and 66)" when, "the correct ratio is: 1 tpy methane = 0.278 tpy VOC."

2. For liquids unloading, in the 2016 RIA, the BLM:
    a. "reversed the sign of the calculated venting increase, and claimed it as an emission reduction in their overall calculations." The API points to Table 7-10a of the 2016 RIA (p. 64) and argues that the 2016 rule's liquids unloading requirements would have resulted in an increase in methane emissions.
    b. "incorrectly assumes that all 1,550 existing wells they determined did not have plunger lift systems and an incremental 25 new wells per year would install plunger lift systems in response to the [rule's] requirements and analyzes the [rule's] impacts based on the incorrect assumption that operators would install plunger lifts even though the rule does not require this."

Table 4.5.9a: API Table of Asserted Corrections (corrections are italicized)

Requirement	2018 Emission Reductions Compiled from BLM's 2016 RIA (tons)		Corrected 2018 Emissions (tons)	
	Methane	VOC	Methane	VOC
Capture Target	No effect	No effect	No effect	No effect
Flare Measurement	No effect	No effect	No effect	No effect
Pneumatic Controllers	18,000	64,900	18,000	*5,004*
Pneumatic Pumps	26,800	7,000	26,800	7,000
Liquids Unloading	34,300	123,000	*-34,300*	*-9,535*
Storage Tanks	7,100	32,500	7,100	32,500
LDAR	89,452	24,761	89,452	24,761
Total	175,652	252,161	*107,052*	*59,730*

The BLM reviewed the API's arguments and found them to be partly correct.

First, regarding item #1, the BLM reviewed the 2016 RIA and agrees with the API that the correct ratio is 1 unit of methane for 0.278 units of VOC.[64] The BLM stated the incorrect ratio in the 2016 RIA and provided incorrect calculations for the VOC reductions attributed to the pneumatic controller and liquids unloading requirements. Further, the BLM carried forward those miscalculated VOC totals to its RIA for the proposed rule. The BLM has corrected those previous VOC miscalculations in this RIA.

Second, regarding item #2a, the BLM reviewed the 2016 RIA and original EPA source from which the BLM derived the data in Table 7-10a in the 2016 RIA. The BLM found that column labels "Gas venting without plunger lifts (Mcfy/well)" and "Gas venting with plunger lifts (Mcfy/well)" were transposed but that the data and the application of the data were correct. The corrected Table 7-10a of the 2016 RIA should read as follows:

[64] See the EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry (2016) at p. 6-7.

Table 4.5.9b: Corrected Table 7-10a forthe 2016 RIA

NEMS REGION	Estimated number of existing wells that would be impacted	Gas venting with plunger lifts (Mcfy/well)	Gas venting without plunger lifts (Mcfy/well)	Difference (Mcfy/well)
Northeast	81	315	166	-149
Midcontinent	54	1380	230	-1150
Rocky Mountain	799	154	2578	2424
Southwest	565	4	97	93
West Coast	4	345	304	-41
Gulf Coast	44	70	301	231
Total	1,547		Weighted Average	1,244

Third, regarding item #2b, the BLM acknowledges the API's comment that the 2016 RIA assumed that the liquids unloading requirements would compel operators to install plunger lifts when the 2016 rule did not make such a requirement. See Section 3.1 of this RIA for a discussion of the issue. For consistency, the BLM presents the estimated impacts of the 2018 final rule, using that assumption, in Section 4. However, the BLM also presents the estimated impacts of the 2018 final rule with an alternate baseline, where the 2016 rule would not have compelled the installation of plunger lifts. See Section 7.3.2 for that analysis.

RFF

Resources for the Future (RFF) submitted comments and attached a technical report assessing the cost savings and foregone benefits of repealing the 2016 rule. RFF argues that the primary driver of the differences in finding is the SC-CH4 estimate. They conduct a cost-benefit analysis of repealing the rule using both a domestic and a global SC-CH4. Both analyses that apply global measures find a net benefit of keeping the final 2016 rule whereas both analyses that apply domestic measures find a net benefit of repealing or revising the final 2016 rule. Specifically, using their own calculated baseline, they find that repealing the final 2016 rule results in net costs of $814 million to $1.2 billion using a global SC-CH4. RFF emphasizes that costs of the rule are borne by private industry whereas benefits of the rule accrue to society.

The authors summarize their main takeaway as: "In deciding whether the rule should be repealed, the Trump administration should take into account that its goal of reducing regulatory burdens has the potential to result in large net costs to society. Even if the administration believes that large net costs are unlikely, it should explicitly consider whether its goal—reducing compliance burdens for industry—warrants even the possibility of these large net costs."

The conclusion in this RIA that the final 2016 rule would have imposed net costs differs from the results contained in the RIA for the 2016 rule. The net-cost result is primarily due to the use of interim values for the domestic Social Cost of Methane (SC-CH4), as opposed to the global values for SC-CH4 that were used in the RIA for the 2016 rule. The rationale for this change is

explained in Section 3.3 and in the Appendix. Another contributing factor is that the gas-capture target provisions would be implemented immediately in 2019. In the RIA for the 2016 rule, the costs of those requirements were delayed to reflect the one-year phase-in period.

WEA/IPAA

The Western Energy Association (WEA) together with the Independent Petroleum Association of America (IPAA) submitted comments generally in support of the final 2018 rule. The commenters agree with the BLM on the significant impact to marginal wells from the 2016 rule while encouraging the BLM to provide an estimate of the number of wells that would be forced to shut-in. A discussion of the impacts on marginal wells is included in section 4.5.6 of this RIA which includes estimated reduction in revenue to marginal wells. The BLM acknowledges that some wells likely would have been shut in under the 2016 rule, however, due to the lack of proprietary cost and revenue data, the BLM was not able to estimate this number. The commenters present their own estimates of the reduction in the number of wells in the table below. The BLM appreciates the commenter's analysis, however, it was conducted using a proprietary model and the BLM was unable to replicate the results.

Table 1
Marginal Well Impact by State on BLM Leases
(2016 BLM Rule vs. Proposed 2018 Rule)

			2016 Enacted Rule			2018 Proposed Rule		
State	BLM Active Wells	BLM Oil Wells	Estimated Cost	Cost Per Well	Est. Marginal Well Reduction	Estimated Cost	Cost Per Well	Est. Marginal Well Reduction
AZ	1	0	$1,420	$7,466	0	$16	$82	0
CO	6,752	3,296	$24,609,136	$7,466	-1,121	$271,654	$82	-225
ID	-	-	$0	$0	0	$0	$0	0
MT	2,742	1,650	$12,317,670	$7,466	-424	$135,971	$82	-11
ND	2,255	2,211	$16,508,474	$7,466	-12	$182,233	$82	0
NE	31	28	$211,286	$7,466	-8	$2,332	$82	-2
NM	30,563	15,092	$112,680,976	$7,466	-5,323	$1,243,854	$82	-104
NV	97	95	$710,562	$7,466	-42	$7,844	$82	-2
OR	-	-	$0	$0	0	$0	$0	0
SD	84	62	$466,601	$7,466	0	$5,151	$82	-15
UT	8,879	4,885	$36,470,000	$7,466	-932	$402,582	$82	-60
WA	-	-	$0	$0	0	$0	$0	0
WY	32,294	10,681	$79,744,572	$7,466	-4,782	$880,278	$82	-259
Total	83,698	38,000	$283,720,696	$7,466	-12,646	$3,131,915	$82	-678

Citizen Group Commenters

The "Citizen Group Commenters," comprised of 34 national, state, and local groups representing public health, conservation, environmental, and tribal citizen interests, submitted comments generally in opposition to the final 2018 rule. To evaluate the BLM's expressed concern over increased shut-in of marginal wells, MJ Bradley and Associates (on behalf of the Citizen Group Commenters) conducted an analysis of marginal well shut-in on BLM-managed lands. This analysis concludes that the decision as to whether or not to shut-in a well appears to be based primarily on production, not revenue, because most wells appear to get shut in when production drops below 5 BOE/day, regardless of natural gas and oil price. This analysis suggests that changes in revenue (including any changes in revenue that may occur due to compliance costs associated with the Waste Prevention Rule) have a limited effect on well shut-in decisions. MJ Bradley and Associates also conducted an analysis of LDAR costs and survey times, and found that annual LDAR compliance costs (as estimated by BLM) would represent less than 1% of total annual revenue for wells on BLM-managed lands for the years 2012-2016.

The methodology used in this analysis did not significantly differ from BLM's analysis of the impact of marginal wells, discussed in section 4.5.6. However, it was not clear how wells were identified as being covered under BLM's authorities. In addition, the data purchased from this analysis was from an industry data company and it was not clear which dataset was used. It is for these reasons that BLM was not able to replicate the results of this analysis.

The citizen group also cited a study by the Conservation Economics Institute that also attempted to assess the impact of the final 2016 rule on marginal wells. The paper conducted a case study of oil and gas wells on Federal land in the San Juan Basin in New Mexico, and found that the impacts of the 2016 rule on small entities would have been more limited than projected by the BLM in the 2016 RIA. The study found that overall compliance costs associated with the 2016 rule represented less than 3% of annual costs for an average marginal well.

The BLM reviewed the analysis that the commenter's referenced and, while we appreciate the information provided, we did not find the results compelling enough to either modify the methodology in this RIA or to change the final policy in this regulatory action. First, while the commenter asserts that the study "found that capture costs will account for less than 3 percent of annual costs for an average marginal well,"[65] the BLM reviewed the referenced analysis and found that its analysis was particular to the 2016 rule's LDAR requirements.[66] Second, the referenced analysis assumes both higher LDAR leak rates and natural gas prices than appropriate. Both factors skew the results to show that LDAR programs are roughly cost-neutral for wells producing 30 Mcf/day and cost-effective for wells producing 60 Mcf/day and 90 Mcf/day. The study assumes a natural gas leak rate of 6% of the gas production, which equates to an amount much higher than that suggested by the EPA's CTG (see discussion in Section 3.2). Next, the referenced study assumes natural gas prices that are higher than the EIA's projections. In its LDAR analysis, the study uses a natural gas price of $2/Mcf in year 1, $3.50/Mcf in year 2, and $5.21 in subsequent years, simulating a 3-year natural gas price recovery in the market. In a second scenario, it assumes $4/Mcf in year 3 and $5.21/Mcf in subsequent years. These prices well above the EIA AEO18 natural gas price forecasts, which have the Henry Hub price below $4/Mcf until 2024 and reaching a 20-year high of $4.43 in 2038 (see Section 3.1). Lastly, the referenced analysis uses prices that are higher than wellhead prices.

[65] Citizen's Group Comment at p. 33.
[66] Conservation Economics Institute study at p. 23, available at https://docs.wixstatic.com/ugd/5fc209_59c6d0e608554ac98fd5ac9b4655fad1.pdf.

5. Statutory and Executive Order Reviews

5.1 Executive Order 12866 Regulatory Planning and Review

E.O. 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to the OMB for review. A rule may be significant under E.O. 12866 if it meets any of four criteria. A significant regulatory action is any rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The OMB has reviewed the BLM's final rule and has determined that it is a significant regulatory action according to the criteria of E.O. 12866.

5.2 Executive Order 13771 Reducing Regulation and Controlling Regulatory Costs

The BLM has complied with E.O. 13771 and the OMB implementation guidance for that order. This final rule removes the substantial compliance burdens of an existing regulation and we estimate that it would result in cost savings. Therefore, this rule is a deregulatory action under Executive Order 13771.

5.3 Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act of 1996

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act, unless the head of the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. (See 5 U.S.C. 601 – 612). Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the SBA size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small

businesses as defined by the SBA. As such, the rule would likely affect a substantial number of small entities.

The BLM reviewed the final rule and estimates that it would generate cost savings of about $72,000 per regulated entity per year. These estimated cost savings would provide relief to small operators which, the BLM notes, represent the overwhelming majority of operators of Federal and Indian leases.

For the purpose of carrying out its review pursuant to the RFA, the BLM believes that the final rule will not have a "significant economic impact on a substantial number of small entities," as that phrase is used in 5 U.S.C. 605. A regulatory flexibility analysis is therefore not required. In making a "significant" determination under the RFA, the BLM used an estimated per-entity cost savings to conduct a screening analysis. The analysis shows that the average reduction in compliance costs associated with this final rule are a small enough percentage of the profit margin for small entities, so as not be considered "significant" under the RFA.

The final rule is a deregulatory action that removes costly requirements placed on operators with the 2016 rule. It also removes substantial administrative burdens that are associated with the 2016 rule's subpart 3179. The 2016 rule contained 24 distinct information collection activities. With this final rule, the BLM is seeking a new OMB control number containing only five information collection activities (only four of which pertain to the revised subpart 3179). The burdens associated with these remaining items are not substantial.

5.4 Unfunded Mandates Reform Act of 1995

Under the Unfunded Mandates Reform Act (UMRA), agencies must prepare a written statement about benefits and costs prior to issuing a rule that is likely to result in an aggregate expenditure by State, local, and tribal governments, or by the private sector, of $100 million or more in any one year, and prior to issuing any final rule for which a rule was published.

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, the rule is also not subject to the requirements of section 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments, because it contains no requirements that apply to such governments, nor does it impose obligations upon them.

5.5 Executive Order 13211 Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Under E.O. 13211, agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. This Statement is to include a detailed statement of "any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increase use of foreign supplies)" for the action and reasonable alternatives and their effects.

Section 4(b) of E.O. 13211 defines a "significant energy action" as "any action by an agency (normally published in the *Federal Register*) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of rulemaking, and notices of rulemaking: (1)(i) that is a significant regulatory action under E.O. 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of [OIRA] as a significant energy action."

The incremental production estimated to result from the final rule represents a small fraction of the total U.S. production. Also, even though the final rule provides regulatory relief from the 2016 rule requirements that pose substantial costs, the reduction in compliance costs represents such a small fraction of company net incomes that we believe that the rule is unlikely to impact the investment decisions of firms. Due to these reasons, we do not expect that this final rule will significantly impact the supply, distribution, or use of energy. As such, the rule is not a "significant energy action" as defined in E.O. 13211.

6. References

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7. Appendix

7.1 Detail of Estimated Administrative Burdens

The following tables present the BLM's reassessment of the administrative burdens. Cells highlighted in blue indicate where assumptions were updated since the BLM published the 2016 RIA. Cells highlighted in green indicate a new requirement in this final rule; therefore no previous estimates were provided in the 2016 RIA. Cells without highlights indicate that no updates were made. Industry burdens were calculated at $65.33 per hour and BLM burdens were calculated at $44.89 per hour.

Development of these values included consultation with BLM State and field offices to determine the level of expected response per provision.

Administrative Burden for Industry (Baseline - 2016 Rule)

Type of Response	Number of Responses	Hours Per Response	Total Hours	Total Burden ($)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1(j) Form 3160-3	3,000	24	72,000	4,703,760
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	8	400	26,132
Notification of Choice to Comply on County- or State-wide Basis 43 CFR 3179.7(c)(3)(iii)	300	2	600	39,198
Request for Approval of Alternative Capture Requirement 43 CFR 3179.8(b) Form 3160-5	75	24	1,800	117,594
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	-	-	-	-
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.101 Form 3160-5	750	2	1,500	97,995
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.102 Form 3160-5	5	2	10	653

Emergencies 43 CFR 3179.103 Form 3160-5	250	2	500	32,665
Notification of Functional Needs for a Pneumatic Controller 43 CFR 3179.201(b)(1) Form 3160-5	10	2	20	1,307
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Controller) 43 CFR 3179.201(b)(4) and 3179.201(c) Form 3160-5	50	8	400	26,132
Showing in Support of Replacement of Pneumatic Controller within 3 Years 43 CFR 3179.201(d) Form 3160-5	100	2	200	13,066
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year 43 CFR 3179.202(b)(2) Form 3160-5	100	2	200	13,066
Notification of Functional Needs for a Pneumatic Diaphragm Pump 43 CFR 3179.202(d) Form 3160-5	150	2	300	19,599
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Diaphragm Pump) 43 CFR 3179.202(f) and (g) Form 3160-5	10	8	80	5,226
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	2	200	13,066
Storage Vessels 43 CFR 3179.203(c) and (d) Form 3160-5	50	24	1,200	78,396
Downhole Well Maintenance and Liquids Unloading - Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	2	10,000	653,300

Downhole Well Maintenance and Liquids Unloading - Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	2	500	32,665
Leak Detection - Compliance with EPA Regulations 43 CFR 3179.301(j) Form 3160-5	50	2	100	6,533
Leak Detection - Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) and (d) Form 3160-5	5	40	200	13,066
Leak Detection - Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	40	800	52,264
Leak Detection - Operator Request for Exemption Allowing Use of Alternative Leak-Detection Program that Does Not Meet Specified Criteria 43 CFR 3179.303(c) and (d) Form 3160-5	500	40	20,000	1,306,600
Leak Detection - Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) and (b) Form 3160-5	100	1	100	6,533
Leak Detection - Inspection Recordkeeping and Reporting 43 CFR 3179.305	52,000	0.25	13,000	849,290
Leak Detection - Annual Reporting of Inspections 43 CFR 3179.305(b) Form 3160-5	2,000	20	40,000	2,613,200
Totals	**64,925**		**164,100**	**10,721,306**

Administrative Burden for Industry (Proposed Rule)

Type of Response	Number of Responses	Hours Per Response	Total Hours	Total Burden ($)
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	8	400	26,132
Request for Extension of Royalty-Free Flaring During Initial Well Testing 43 CFR 3179.101 Form 3160-4	750	2	1,500	97,995
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.102 Form 3160-5	5	2	10	653
Emergencies 43 CFR 3179.103 Form 3160-5	250	2	500	32,665
Oil Well Gas 43 CFR 3179.201	20	80	1,600	104,528
Totals	**1,075**		**4,010**	**261,973**

Administrative Burden for BLM (Baseline - 2016 Rule)

Type of Response	Number of Responses	Hours Per Response	Total Hours	Total Burden ($)
Plan to Minimize Waste of Natural Gas 43 CFR 3162.3-1(j) Form 3160-3	3,000	6	18,000	808,020
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	4	200	8,978
Notification of Choice to Comply on County- or State-wide Basis 43 CFR 3179.7(c)(3)(iii)	300	0.25	75	3,367
Request for Approval of Alternative Capture Requirement 43 CFR 3179.8(b) Form 3160-5	75	8	600	26,934
Request for Exemption from Well Completion Requirements 43 CFR 3179.102(c) and (d) Form 3160-5	-	-	-	-
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.101 Form 3160-5	750	1	750	33,668
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.102 Form 3160-5	5	1	5	224
Emergencies 43 CFR 3179.103 Form 3160-5	250	2	500	22,445
Notification of Functional Needs for a Pneumatic Controller 43 CFR 3179.201(b)(1) Form 3160-5	10	0.25	3	112
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Controller) 43 CFR 3179.201(b)(4) and 3179.201(c) Form 3160-5	50	3	150	6,734

Showing in Support of Replacement of Pneumatic Controller within 3 Years 43 CFR 3179.201(d) Form 3160-5	100	0.25	25	1,122
Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year 43 CFR 3179.202(b)(2) Form 3160-5	100	0.25	25	1,122
Notification of Functional Needs for a Pneumatic Diaphragm Pump 43 CFR 3179.202(d) Form 3160-5	150	0.25	38	1,683
Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Diaphragm Pump) 43 CFR 3179.202(f) and (g) Form 3160-5	10	3	30	1,347
Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years 43 CFR 3179.202(h) Form 3160-5	100	0.25	25	1,122
Storage Vessels 43 CFR 3179.203(c) and (d) Form 3160-5	50	3	150	6,734
Downhole Well Maintenance and Liquids Unloading - Documentation and Reporting 43 CFR 3179.204(c) and (e) Form 3160-5	5,000	0.25	1,250	56,113
Downhole Well Maintenance and Liquids Unloading - Notification of Excessive Duration or Volume 43 CFR 3179.204(f) Form 3160-5	250	0.5	125	5,611
Leak Detection - Compliance with EPA Regulations 43 CFR 3179.301(j) Form 3160-5	50	0.25	13	561
Leak Detection - Request to Use an Alternative Monitoring Device and Protocol 43 CFR 3179.302(c) and (d) Form 3160-5	5	160	800	35,912

Leak Detection - Operator Request to Use an Alternative Leak Detection Program 43 CFR 3179.303(b) Form 3160-5	20	80	1,600	71,824
Leak Detection - Operator Request for Exemption Allowing Use of Alternative Leak-Detection Program that Does Not Meet Specified Criteria 43 CFR 3179.303(c) and (d) Form 3160-5	500	80	40,000	1,795,600
Leak Detection - Notification of Delay in Repairing Leaks 43 CFR 3179.304(a) and (b) Form 3160-5	100	0.5	50	2,245
Leak Detection - Inspection Recordkeeping and Reporting 43 CFR 3179.305	52,000	0.0833	4,333	194,523
Leak Detection - Annual Reporting of Inspections 43 CFR 3179.305(b) Form 3160-5	2,000	2	4,000	179,560
Totals	**64,925**		**72,746**	**3,265,560**

Administrative Burden for BLM (Proposed Changes)

Type of Response	Number of Responses	Hours Per Response	Total Hours	Total Burden ($)
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	4	200	8,978
Request for Extension of Royalty-Free Flaring During Initial Well Testing 43 CFR 3179.101 Form 3160-4	750	1	750	33,668
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.102 Form 3160-5	5	1	5	224
Emergencies 43 CFR 3179.103 Form 3160-5	250	2	500	22,445
Oil Well Gas 43 CFR 3179.201	20	24	480	21,547
Totals	**1,075**		**1,935**	**86,862**

7.2 Interim $SC\text{-}CH_4$ Estimates and Associated Uncertainty

As discussed in Section 3.3 of this RIA, the BLM estimated the forgone climate benefits from the final rule using interim estimates of the domestic social cost of methane (SC-CH4). These SC-CH4 estimates developed under E.O. 13783 will be used in regulatory analysis until final domestic estimates can be developed, which will take into consideration the recent recommendations from the National Academies of Sciences, Engineering, and Medicine for a comprehensive update to the current methodology to ensure that the social cost of greenhouse gas estimates reflect the best available science while also comporting with the procedures set forth in OMB Circular A-4. While the Academies' review focused on the methodology to estimate the social cost of carbon (SC-CO2), the recommendations on how to update many of the underlying modeling assumptions also pertain to the SC-CH4 estimates since the framework used to estimate SC-CH4 is the same as that used for SC-CO2. The following discussion describes the methodology used to develop these estimates and the ways in which the modeling addressed quantified sources of uncertainty.

The domestic $SC\text{-}CH_4$ estimates rely on an ensemble of three integrated assessment models (IAMs): DICE 2010, FUND 3.8, and PAGE 2009.[67] The three IAMs translate emissions into changes in atmospheric greenhouse concentrations, atmospheric concentrations into changes in temperature, and changes in temperature into economic damages. The emissions projections used in the models are based on specified socio-economic (GDP and population) pathways. These emissions are translated into atmospheric concentrations, and concentrations are translated into warming based on each model's simplified representation of the climate and a key parameter, equilibrium climate sensitivity. The effect of these Earth system changes is then translated into consumption-equivalent economic damages. These key inputs were harmonized across the three models: A probability distribution for equilibrium climate sensitivity; five scenarios for economic, population, and emissions growth; and discount rates. Future damages are discounted using constant discount rates of both 3 and 7 percent, as recommended by OMB Circular A-4.

The domestic share of the global $SC\text{-}CH_4$—i.e., an approximation of the climate change impacts that occur within U.S. borders—is calculated directly in both FUND and PAGE. However, DICE 2010 generates only global estimates. Therefore, U.S. damages are approximated as 10% of the global values from the DICE model runs, based on the results from a regionalized version of the model (RICE 2010) reported in Table 2 of Nordhaus (2017).[68] Although the regional shares reported in Nordhaus (2017) are specific to $SC\text{-}CO_2$, they still provide a reasonable interim approach for approximating the U.S. share of marginal damages from methane emissions. Direct transfer of the domestic share from the $SC\text{-}CO_2$ may understate the U.S. share of the global $SC\text{-}CH_4$ estimates based on DICE due to the combination of three factors: a) Regional damage estimates are known to be highly correlated with output shares (Nordhaus 2017, 2014); b) The U.S. share of global output decreases over time in all five EMF-22 based socioeconomic scenarios used for the model runs; and c) The bulk of the temperature anomaly (and hence,

[67] The full models names are as follows: Dynamic Integrated Climate and Economy (DICE); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND); and Policy Analysis of the Greenhouse Gas Effect (PAGE).

[68] Nordhaus, William D. 2017. Revisiting the social cost of carbon. *Proceedings of the National Academy of Sciences of the United States,* 114(7): 1518-1523.

resulting damages) from a perturbation in emissions in a given year will be experienced earlier for CH_4 than CO_2 due to the shorter lifetime of CH_4 relative to CO_2.

The steps involved in estimating the social cost of CH_4 is similar to that of CO_2. The three integrated assessment models (FUND, DICE, and PAGE) are run using the harmonized equilibrium climate sensitivity distribution, five socioeconomic and emissions scenarios, constant discount rates described above. Because the climate sensitivity parameter is modeled probabilistically, and because PAGE and FUND incorporate uncertainty in other model parameters, the final output from each model run is a distribution over the SC-CH_4 in year "t" based on a Monte Carlo simulation of 10,000 runs. For each of the IAMs, the basic computational steps for calculating the social cost estimate in a particular year t are: 1) Calculate the temperature effects and (consumption-equivalent) damages in each year resulting from the baseline path of emissions; 2) Adjust the model to reflect an additional unit of emissions in year t; 3) Recalculate the temperature effects and damages expected in all years beyond t resulting from this adjusted path of emissions, as in step 1; and 4) Subtract the damages computed in step 1 from those in step 3 in each model period and discount the resulting path of marginal damages back to the year of emissions. In PAGE and FUND step 4 focuses on the damages attributed to the US region in the models. As noted above, DICE does not explicitly include a separate US region in the model and therefore, US damages are approximated in step 4 as 10% of the global values based on the results of Nordhaus (2017). This exercise produces 30 separate distributions of the SC-CH_4 for a given year, the product of 3 models, 2 discount rates, and 5 socioeconomic scenarios. The estimates are equally weighted across models and socioeconomic scenarios in order to consolidate the results into one distribution for each discount rate.

The following table presents the average domestic SC-CH_4 estimates across all the model runs for each discount rate for the years 2015 to 2050. As with the global SC-CH_4 estimates, the domestic SC-CH_4 increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to gross GDP.

Table. Interim Domestic Social Cost of CH_4, 2015-2020 (in 2016$ per metric ton CH_4)*

	Discount Rate and Statistic	
Year	7% Average	3% Average
2015	$46	$150
2020	55	180
2025	68	200
2030	81	230
2035	96	260
2040	110	290
2045	130	330
2050	140	350

* SC-CH_4 values are stated in $/metric ton CH_4 and rounded to two significant digits. The estimates vary depending on the year of CH_4 emissions and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

The limitations and uncertainties associated with the global SC-CH_4 estimates, which were discussed in detail in the 2016 RIA, likewise apply to the domestic SC-CH_4 estimates presented in this analysis. Some uncertainties are captured within the analysis, as discussed in detail in this appendix, while other areas of uncertainty have not yet been quantified in a way that can be modeled. As with the methodology used to calculate SC-CO_2 estimates, limitations include the incomplete or inadequate representation in the integrated assessment models of several important factors: Catastrophic and non-catastrophic impacts, adaptation and technological change, inter-regional and inter-sectoral linkages, uncertainty in the extrapolation of damages to high temperatures, and the relationship between the discount rate and uncertainty in economic growth over long time horizons. The science incorporated into these models understandably lags behind the most recent research, and the limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult.

There are several limitations specific to the estimation of SC-CH_4. For example, the SC-CH_4 estimates do not reflect updates from the IPCC regarding atmospheric and radiative efficacy. Another limitation is that the SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane. In addition, the SC-CH_4 estimates do not reflect that methane emissions lead to a reduction in atmospheric oxidants, like hydroxyl radicals, nor do they account for impacts associated with CO_2 produced from methane oxidizing in the atmosphere. These individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CH_4 estimates.

Recognizing the limitations and uncertainties associated with estimating the social cost of greenhouse gases, the research community has continued to explore opportunities to improve estimates of SC-CO_2 and other greenhouse gases.

Treatment of Uncertainty in Interim Domestic SC-CH_4 Estimates

In order to adhere to the principles of full disclosure and transparency of Circular A-4, this analysis relies on data and models that contain a significant degree of uncertainty. As an interim approach, until a more comprehensive update can be completed, this RIA relies upon the inputs and modeling developed by the now-disbanded Interagency Working Group for the purposes of providing discrete alternative scenarios that reflect the best available Federal agency estimates of social costs.

There are other sources of uncertainty in the SC-CH_4 estimates used in this RIA. Some uncertainties pertain to aspects of the natural world, such as quantifying the physical effects of greenhouse gas emissions on Earth systems. Other sources of uncertainty are associated with current and future human behavior and well-being, such as population and economic growth, GHG emissions, the translation of Earth system changes to economic damages, and the role of adaptation. It is important to note that even in the presence of uncertainty, scientific and economic analysis can provide valuable information to the public and decision makers, though the uncertainty should be acknowledged and when possible taken into account in the analysis (National Academies 2013).[69]

[69] Institute of Medicine of the National Academies. 2013. Environmental Decisions in the Face of Uncertainty. The National Academies Press.

The domestic SC-CH_4 estimates consider various sources of uncertainty through a combination of a multi-model ensemble, probabilistic analysis, and scenario analysis. We provide a summary of this analysis here; more detailed discussion of each model and the harmonized input assumptions can be found in the 2017 National Academies report. For example, the three IAMs used collectively span a wide range of Earth system and economic outcomes to help reflect the uncertainty in the literature and in the underlying dynamics being modeled. The use of an ensemble of three different models at least partially addresses the fact that no single model includes all of the quantified economic damages. It also helps to reflect structural uncertainty across the models, which stems from uncertainty about the underlying relationships among GHG emissions, Earth systems, and economic damages that are included in the models. Bearing in mind the different limitations of each model and lacking an objective basis upon which to differentially weight the models, the three integrated assessment models are given equal weight in the analysis.

Monte Carlo techniques were used to run the IAMs a large number of times. In each simulation the uncertain parameters are represented by random draws from their defined probability distributions. In all three models the equilibrium climate sensitivity is treated probabilistically based on the probability distribution from Roe and Baker (2007) calibrated to the IPCC AR4 consensus statement about this key parameter.[70] The equilibrium climate sensitivity is a key parameter in this analysis because it helps define the strength of the climate response to increasing GHG concentrations in the atmosphere. In addition, the FUND and PAGE models define many of their parameters with probability distributions instead of point estimates. For these two models, the model developers' default probability distributions are maintained for all parameters other than those superseded by the harmonized inputs (i.e., equilibrium climate sensitivity, socioeconomic and emissions scenarios, and discount rates).

For the socioeconomic and emissions scenarios, uncertainty is included in the analysis by considering a range of scenarios selected from the Stanford Energy Modeling Forum exercise, EMF-22. Given the dearth of information on the likelihood of a full range of future socioeconomic pathways at the time the original modeling was conducted, and without a basis for assigning differential weights to scenarios, the range of uncertainty was reflected by simply weighting each of the five scenarios equally for the consolidated estimates.

The outcome of accounting for various sources of uncertainty using the approaches described above is a frequency distribution of the SC-CH_4 estimates for emissions occurring in a given year for each discount rate. Unlike the approach taken for consolidating results across models and socioeconomic and emissions scenarios, the SC-CH_4 estimates are not pooled across different discount rates because the range of discount rates reflects both uncertainty and, at least in part, different policy or value judgements; uncertainty regarding this key assumption is discussed in more detail below. The frequency distributions reflect the uncertainty around the input parameters for which probability distributions were defined, as well as from the multi-model ensemble and socioeconomic and emissions scenarios where probabilities were implied by the equal weighting assumption. It is important to note that the set of SC-CH_4 estimates

[70] Specifically, the Roe and Baker distribution for the climate sensitivity parameter was bounded between 0 and 10 with a median of 3 °C and a cumulative probability between 2 and 4.5 °C of two-thirds.

obtained from this analysis does not yield a probability distribution that fully characterizes uncertainty about the SC-CH_4 due to impact categories omitted from the models and sources of uncertainty that have not been fully characterized due to data limitations.

The following figure presents the frequency distribution of the domestic SC-CH_4 estimates for emissions in 2020 for each discount rate. Each distribution represents 150,000 estimates based on 10,000 simulations for each combination of the three models and five socioeconomic and emissions scenarios.[71] In general, the distributions are skewed to the right and have long right tails, which tend to be longer for lower discount rates. To highlight the difference between the impact of the discount rate on the SC-CH_4 and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CH_4 estimates conditioned on each discount rate.

Circular A-4 recommends that costs and benefits be discounted using rates of 3% and 7% to reflect the opportunity cost of consumption and capital, respectively. As illustrated by the frequency distributions in the figure, the assumed discount rate plays a critical role in the ultimate estimate of the social cost of methane.

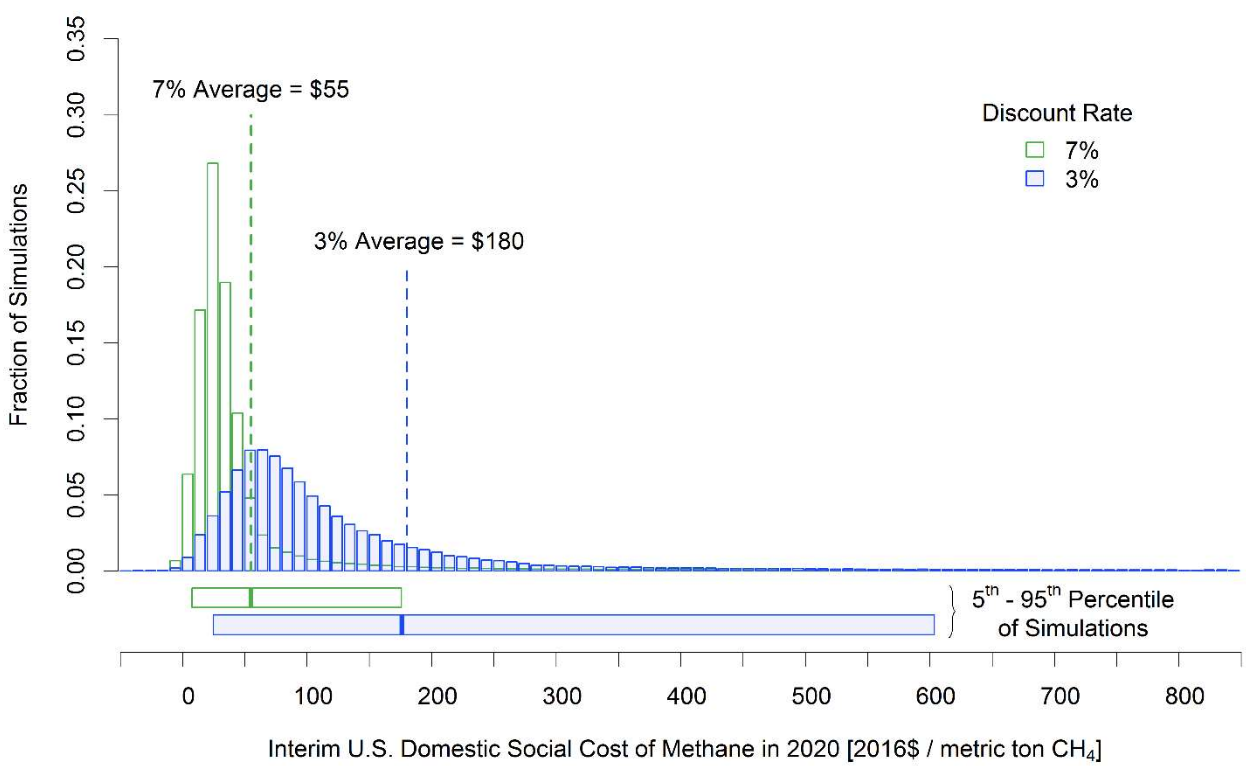

Figure. Frequency Distribution of Interim Domestic SC-CH_4 Estimates for 2020 (in 2016$ per metric ton CH_4)

[71] Although the distributions in the figure are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.001 to 0.013 percent of the estimates lying below the lowest bin displayed and 0.471 to 3.356 percent of the estimates lying above the highest bin displayed, depending on the discount rate.

In addition to the approach to accounting for the quantifiable uncertainty described above, the scientific and economics literature has further explored known sources of uncertainty related to estimates of the social cost of carbon and other greenhouse gases. For example, researchers have examined the sensitivity of IAMs and the resulting estimates to different assumptions embedded in the models (see, e.g., Pindyck 2013, Hope 2013, Anthoff and Tol 2013, Nordhaus 2014, and Waldhoff et al. 2011, 2014). However, there remain additional sources of uncertainty that have not been fully characterized and explored due to remaining data limitations. Additional research is needed to expand the quantification of various sources of uncertainty in estimates of the social cost of carbon and other greenhouse gases (e.g., developing explicit probability distributions for more inputs pertaining to climate impacts and their valuation). On the issue of intergenerational discounting, some experts have argued that a declining discount rate would be appropriate to analyze impacts that occur far into the future (Arrow et al., 2013). On damage functions, other experts have found that those used in most IAMs have no theoretical or empirical foundation, claiming that the overall model is able to "obtain almost any result one desires" (Pindyck 2013). Naturally, the indeterminate amount of uncertainty surrounding the IAMs used to approximate social costs for specific greenhouse gas emissions merits additional research and analysis and further peer-review in order to better ascertain the best available science and economics in accordance with E.O. 13783.

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7.3 Alternative Analyses

7.3.1 Table of Results for Sensitivity Analysis, Alternative Natural Gas Prices

The following table contains the results of the analysis using alternative natural gas prices. It accounts for natural gas prices that are 89% of the EIA's projections. The basis for this assumption is an EIA analysis from 2002, which found that Henry Hub prices were, on average, about 11% higher than wellhead prices.

	Discount Rate	Time Period	Baseline (No Action)	2018 Rule	Impact of 2018 Rule
Compliance Costs	7%	10-Year Total	$1.370 to $1.645 billion	$2.29 million	($1.368) to ($1.643) billion
		Annualized	$195 to $234 million	$0.33 million	($195) to ($234) million
	3%	10-Year Total	$1.726 to $2.089 billion	$2.89 million	($1.723) to ($2.087) billion
		Annualized	$202 to $245 million	$0.41 million	($202) to ($245) million
Cost Savings from Natural Gas Recovery	7%	10-Year Total	$631 million	$0	($631) million
		Annualized	$90 million	$0	($90) million
	3%	10-Year Total	$829 million	$0	($829) million
		Annualized	$97 million	$0	($97) million
Methane Reductions		10-Year Total	1.78 million tons	0 tons	(1.78) million tons
		Annual	175,000 to 180,000 tons	0 tons	(175,000) to (180,000) tons
Value of Methane Reductions	7%	10-Year Total	$66 million	$0	($66) million
		Annualized	$9.42 million	$0	($9.42) million
	3%	10-Year Total	$259 million	$0	($259) million
		Annualized	$30.4 million	$0	($30.4) million
VOC Reductions		10-Year Total	798,000 tons	0	(798,000) tons
		Annual	79,000 to 80,000 tons	0	(79,000) to (80,000) tons
Net Benefits	7%	10-Year Total	($673) to ($948) million	($2) million	$671 to $946 million
		Annualized	($96) to ($135) million	($0.33) million	$96 to $135 million
	3%	10-Year Total	($638) million to ($1.002) billion	($3) million	$635 to $999 million
		Annualized	($75) to ($117) million	($0.34) million	$74 to $117 million
Incremental Royalty	7%	10-Year Total	$42.0 million	$0	($42.0) million
		Annualized	$5.97 million	$0	($5.97) million
	3%	10-Year Total	$97.3 million	$0	($97.3) million
		Annualized	$11.4 million	$0	($11.4) million

7.3.2 Alternate Baseline for Liquids Unloading

The following table contains the alternate baseline (where the 2016 rule would not have compelled the installation of plunger lifts) and a recalculated of impacts associated with the 2018 final rule against that alternate baseline.

	Discount Rate	Time Period	Alternative Baseline (No Action)	2018 Rule	Impact of 2018 Rule Against Alternative Baseline
Compliance Costs	7%	10-Year Total	$1.323 to $1.598 billion	$2.29 million	($1.321) to ($1.596) billion
		Annualized	$188 to $228 million	$0.33 million	($188) to ($227) million
	3%	10-Year Total	$1.671 to $2.035 billion	$2.89 million	($1.668) to ($2.032) billion
		Annualized	$196 to $239 million	$0.41 million	($196) to ($238) million
Cost Savings from Natural Gas Recovery	7%	10-Year Total	$519 million	$0	($519) million
		Annualized	$74 million	$0	($74) million
	3%	10-Year Total	$682 million	$0	($682) million
		Annualized	$80 million	$0	($80) million
Methane Reductions		10-Year Total	1.41 million tons	0 tons	(1.41) million tons
		Annual	141,000 tons	0 tons	(141,000) tons
Value of Methane Reductions	7%	10-Year Total	$53 million	$0	($53) million
		Annualized	$7.49 million	$0	($7.49) million
	3%	10-Year Total	$206 million	$0	($206) million
		Annualized	$24.1 million	$0	($24.1) million
VOC Reductions		10-Year Total	697,000 tons	0	(697,000) tons
		Annual	69,700 tons	0	(69,700) tons
Net Benefits	7%	10-Year Total	($752) million to ($1.027) billion	($2) million	$750 million to $1.025 billion
		Annualized	($107) to ($146) million	($0.33) million	$107 to $146 million
	3%	10-Year Total	($784) million to ($1.147) billion	($3) million	$781 million to $1.145 billion
		Annualized	($92) to ($135) million	($0.34) million	$92 to $134 million
Incremental Royalty	7%	10-Year Total	$23.2 million	$0	($23.2) million
		Annualized	$3.31 million	$0	($3.31) million
	3%	10-Year Total	$72.6 million	$0	($72.6) million
		Annualized	$8.51 million	$0	($8.51) million

7.4 Comparison of Estimated Impacts of the 2016 Rule (in 2016 RIA and 2018 RIA) and Impacts of the 2018 Rule

The following table compares the estimated impacts of the 2016 rule (described in the 2016 RIA with corrected calculations) and the re-estimated impacts of the 2016 rule (described in the 2018 RIA and used for its baseline). The right column shows the estimated impacts of the 2018 final rule.

	Discount Rate	Time Period	Impacts of the 2016 Rule, 2017 - 2026 (estimated in the 2016 RIA or corrected)	Impacts of the 2016 Rule, 2019 - 2028 (Re-estimated in the 2018 RIA and used as its baseline)	Impacts of the 2018 Rule, 2019 - 2028
Compliance Costs	7%	10-Year Total	$1.241 to $1.453 billion	$1.362 to $1.637 billion	($1.359) to ($1.634) billion
		Annualized	$177 to $207 million[1]	$194 to $233 million	($194) to ($233) million
	3%	10-Year Total	$1.464 to $1.816 billion	$1.715 to $2.079 billion	($1.712) to ($2.076) billion
		Annualized	$172 to $213 million[1]	$201 to $244 million	($201) to ($243) million
Cost Savings from Natural Gas Recovery	7%	10-Year Total	$603 million	$559 million	($559) million
		Annualized	$86 million[1]	$80 million	($80) million
	3%	10-Year Total	$764 million	$734 million	($734) million
		Annualized	$90 million[1]	$86 million	($86) million
Methane Reductions		10-Year Total	1.78 million tons	1.78 million tons	(1.78) million tons
		Annual	175,000 to 180,000 tons	175,000 to 180,000 tons	(175,000) to (180,000) tons
Value of Methane Reductions	7%	10-Year Total	$1.620 billion	$66 million	($66) million
		Annualized	$231 million[1]	$9.42 million	($9.42) million
	3%	10-Year Total	$1.914 billion	$259 million	($259) million
		Annualized	$244 million[1]	$30.4 million	($30.4) million
VOC Reductions		10-Year Total	798,000 tons[2]	798,000 tons	(798,000) tons
		Annual	79,000 to 80,000 tons[3]	79,000 to 80,000 tons	(79,000) to (80,000) tons
Net Benefits	7%	10-Year Total	$740 million to $1.014 billion	($736) million to ($1.011) billion	$734 million to $1.009 billion
		Annualized	$105 to $144 million[1]	($105) to ($144) million	$104 to $144 million
	3%	10-Year Total	$862 million to $1.214 billion	($722) million to ($1.086) billion	$720 million to $1.083 billion
		Annualized	$101 to $142 million[1]	($85) to ($127) million	$84 to $127 million
Incremental Royalty	7%	10-Year Total	$45.8 million[4]	$28.3 million	($28.3) million
		Annualized	$6.53 million[1]	$4.03 million	($4.03) million
	3%	10-Year Total	$103 million[5]	$79.1 million	($79.1) million
		Annualized	$14.67 million[1]	$9.27 million	($9.27) million

[1] Not reported in the 2016 RIA. Calculated and provided here for comparison purposes.
[2] Corrected. The original 2016 RIA estimate of 2.59 million tons was miscalculated.
[3] Corrected. The original 2016 RIA estimate of 250,000 to 267,000 tons was miscalculated.
[4] Corrected. The original 2016 RIA estimate of $65.4 million was miscalculated.
[5] Corrected. The original 2016 RIA estimate of $82.3 million tons was miscalculated.

7.5 Methodology Used to Estimate the Impacts of the 2016 Rule's Gas Capture Requirements

This section describes the methods used to estimate the impacts of the 2016 Rule's gas capture requirements. The methods were used in the 2016 RIA and were carried forward into the 2018 RIA.

To analyze the impacts of potentially limiting flaring on Federal and Indian lands, the BLM requested oil and gas disposition data for all onshore activity reported to ONRR during FY 2015. This resulted in 816,231 observations with the unit of analysis being an operator's monthly volume of gas for each relevant disposition code. The data allowed for various extractions of data by date, operator, lease/unit, county, state, land class, and disposition code.

The various disposition codes describe the volumes of oil and gas that are sold, vented, flared, and used on lease among other actions. We modified the analysis over time, as early results revealed different aspects of flaring behavior on the lands of interest. One limitation of the data is in the land class. The land class types are Federal, Indian, State, Fee and Mixed. While we would like to focus on only Federal and Indian flared volumes for the purpose of this analysis, a record falls into the "mixed" category if any of the pervious varieties are in the unit/lease reported. Nearly 78 percent of the records are mixed. However; according to ONRR, about 50 percent of gas and 27 percent of oil production belongs to Federal and about 4 percent of the gas and 10 percent of the oil belongs to Indian lands.

The 2016 rule allows operators to group their production (at their option) across a State or county (as well as a unit/lease). As averaging the production across the State was seemingly the most advantageous to the operator, a further analysis was completed at the State level. To that end, spreadsheets were created to analyze the data state-by-state.

From the 800,000 plus records, each State specific set of records were extracted to the State spreadsheet template. For example, the North Dakota (ND) spreadsheet contains 84,604 records while the New Mexico (NM) spreadsheet has 297,268 records. Next the unique state and operator combinations were determined. For example, ND had 76 unique operators and NM had 354. To calculate a capture target percent for each operator in a State, relevant records had to be combined and then appropriately added or subtracted. We performed the calculations for each of the top flaring States: ND, NM, Wyoming (WY), Montana (MT), Colorado (CO), Utah (UT), California (CA), and South Dakota (SD). According to ONRR records, these eight States represented about 99.7 percent of the flaring reported from oil wells on Federal and Indian lands (including the mixed volumes).

We used the operator data in each state to determine the volume of flaring that would be allowed by the 2016 rule and the volume of excess flaring that would have occurred in FY 2015, for each of the specified flaring allowable volumes and capture targets shown in Table 7.5a.[72] We then calculated the volume of excess flaring that would have occurred in FY 2015 with and without the 2016 rule in each of the eight top flaring states listed above.

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[72] We note that the baseline for the 2016 RIA assumed that the initial compliance would begin in 2018. The 2018 RIA assumes compliance would begin in 2019.

Table 7.5a: Schedule for Flaring Allowable and Natural Gas Capture Targets

Year	Flaring Allowable (Mcf/ Well/ Month)	Capture Target - Percent (%)
2019	5400	85%
2020	3600	85%
2021	1800	90%
2022	1500	90%
2023	1200	90%
2024	1200	95%
2025	900	95%
2026	750	95%
2027	750	98%
2028	750	98%

Since the 2016 rule allowed operators to average across all their oil operations, even as broadly as statewide, it became much more difficult to predict how operators will respond to meet the requirements for flaring reductions. Without this location information or cost data on each individual oil operator and operation, it was difficult to ascertain on which locations operators might focus to reduce flaring. Thus, in order to generate an estimate of the likely costs of reducing these flared volumes in each state, it was necessary to make certain assumptions regarding how operators could respond to the requirements to meet these capture targets.

Table 7.5b below illustrates how the percentage of the flaring controlled in each year is allocated between three avenues.[73] These include Capacity buildout, Curtailment and CNG Trucking. First, we totaled Energy Information Administration data for pipeline outflow capacity for the Southwest and Western region over 2005 to 2015 and did a regression analysis. During this time period, the pipeline outflow capacity increased 2% per year. This growth was used to model projections going forward as the baseline for pipeline capacity.. For the analysis, capacity buildout does not carry with it any costs or benefits attributed to the requirements, as it effectively reduces the baseline of the yearly amount of flaring reduction required to be achieved by these requirements. Table 7.5c shows the amount of flaring that will be reduced by this rule as a total volume, incremental volume and an incremental increase in flaring prevented.

[73] We note that the baseline for the 2016 RIA assumed that the initial compliance would begin in 2018. The 2018 RIA assumes compliance would begin in 2019. For 2028, we maintained the 2% assumed capacity buildout assumption to replace CNG trucking volumes.

Table 7.5b: Percentage of Yearly Flaring Reductions Allocated to each Approach

Year	Flaring Allowable (Mcf/ month) [1]	Capture Target[2]	Capt Tar Vol Flared (Bcf)	Capacity Buildout	Curtailmen t	CNG Trucking
2019	5400	85%	7.80	2%	5%	93%
2020	3600	85%	10.70	4%	10%	86%
2021	1800	90%	17.50	6%	15%	79%
2022	1500	90%	21.30	8%	20%	72%
2023	1200	90%	25.50	10%	15%	75%
2024	1200	95%	27.80	12%	10%	78%
2025	900	95%	34.40	14%	5%	81%
2026	750	95%	39.50	16%	5%	79%
2027	750	98%	40.50	18%	5%	77%
2028	750	98%	40.50	20%	5%	75%

[1] Per well (averaged over all wells in a state by operator)
[2] Percent reduction required of an operators total flaring ABOVE the allowable limit

Curtailment is the first flaring reduction strategy we model for operators to meet each year's requirement for flaring reductions. The schedule for the amount of flaring reduced each year via curtailment is essentially a BLM assumption based on prices and likely operator responses. The cost of curtailment is calculated as the difference between the present value of selling oil and gas in each year versus 10 years later. Rates of 7% and 3% are used for the "opportunity cost" of oil and gas deferred.[74] In this circumstance, operators are basically slowing their rate of production by the volume of gas necessary to meet a percentage of the flaring requirements. The associated amount of oil that would need to be deferred as a result of gas curtailment is estimated using the average Gas to Oil Ratio (GOR) for each state individually before the totals are summed together.

Furthermore, the BLM maintained an assumption used in the 2016 RIA which applied an adder equivalent to 10% of the price of oil in the year of curtailment to the total cost of curtailment, to account for additional costs associated with deferring production.[75] These additional costs could include: (1) fixed costs associated with servicing debt and other capital expenses, (2) potential penalties associated with term contracts that require providing a set volume of oil at set points in time, (3) well productivity decline from deferred production, leading to potential reduction in total recovery over the life of the well, and (4) permanent well shut-ins for wells that would need to defer significant production in order to comply with the rule. The cost of the gas capture requirement without the adder represents the lower bound of the cost estimation. The cost of the gas capture requirement with the adder represents the upper bound of the cost estimation.

Onsite capture is the second strategy we model for operators to reduce flaring. However, in response to public comments concerning the 2016 rule regarding the capacity of NGL recovery to deal with large volumes of flaring, that method of onsite capture was not modeled in the 2016 RIA

[74] We note that the 2018 RIA adds the 3% opportunity cost for use with the NPV3 calculations.
[75] This was done in response to a public commenter's suggestion during the development of the 2016 rule.

or the 2018 RIA as a means by which operators would likely reduce excess flaring. We model the use of CNG trucking, as it is a low cost method of onsite capture. This analysis assumes that all reduction in excess flaring that is not addressed by the declining baseline due to capacity buildout or reduced by operators curtailing production will be achieved by CNG trucking. The costs for CNG trucking are derived from a Carbon Limits study in 2015 which present operating costs between \$0.24 and \$1.30 per Mcf produced and capital costs between \$400 and \$2,000 per Mcf of flowrate (expressed as Mcf/day).[76]

[76] Carbon Limits (April 2015) *Improving utilization of associated gas in US tight oil fields Appendix* page 4.

FINDING OF NO SIGNIFICANT IMPACT
U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements Final Rule
DOI-BLM-WO310-2018-0001-EA

INTRODUCTION

The Bureau of Land Management (BLM) has prepared an Environmental Assessment (DOI-BLM-WO-WO310-2018-0001-EA) ("EA") to examine the environmental impacts that may occur as a result of rescinding or revising certain requirements imposed by the Bureau of Land Management's (BLM) 2016 rule, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" ("2016 rule") (See 81 FR 83008 (Nov. 18, 2016)). The 2016 rule applied nationwide to onshore Federal and Indian oil and gas development. The provisions of the 2016 rule relevant to this EA pertained to the loss of Federal and Indian natural gas through venting, flaring, and leaks. The Proposed Action is evaluated as Alternative B in the EA. The EA also includes an evaluation for a No-Action Alternative (Alternative A) and an alternative in which the "gas capture requirements" of the 2016 rule would be retained (Alternative C). This Finding of No Significant Impact (FONSI) is attached to, and incorporates by reference, the analysis contained in the EA.

FINDING OF NO SIGNIFICANT IMPACT

Pursuant to the National Environmental Policy Act (NEPA), 42 U.S.C. 4321 *et seq.*, the BLM must prepare an Environmental Impact Statement (EIS) for each proposed major Federal action significantly affecting the quality of the human environment before making a decision on whether to proceed with the proposed action. 43 CFR 46.400. The preparation of an EA allows the BLM to determine whether a proposed action would have a significant impact on the environment, and, therefore, whether an EIS must be prepared. 43 CFR 46.300.

In determining whether a proposed action would "significantly" impact the environment, the BLM is guided by the Council on Environmental Quality (CEQ) regulations implementing the NEPA at 40 CFR 1508.27, which define "significantly" as follows:

> *Significantly* as used in NEPA requires considerations of both context and intensity:
>
> (a) *Context.* This means that the significance of an action must be analyzed in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality. Significance varies

with the setting of the proposed action. For instance, in the case of a site-specific action, significance would usually depend upon the effects in the locale rather than in the world as a whole. Both short- and long-term effects are relevant.

(b) *Intensity*. This refers to the severity of impact. Responsible officials must bear in mind that more than one agency may make decisions about partial aspects of a major action. The following should be considered in evaluating intensity:

(1) Impacts that may be both beneficial and adverse. A significant effect may exist even if the Federal agency believes that on balance the effect will be beneficial.

(2)The degree to which the proposed action affects public health or safety.

(3) Unique characteristics of the geographic area such as proximity to historic or cultural resources, park lands, prime farmlands, wetlands, wild and scenic rivers, or ecologically critical areas.

(4) The degree to which the effects on the quality of the human environment are likely to be highly controversial.

(5) The degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks.

(6) The degree to which the action may establish a precedent for future actions with significant effects or represents a decision in principle about a future consideration.

(7) Whether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts.

(8) The degree to which the action may adversely affect districts, sites, highways, structures, or objects listed in or eligible for listing in the National Register of Historic Places or may cause loss or destruction of significant scientific, cultural, or historical resources.

(9) The degree to which the action may adversely affect an endangered or threatened species or its habitat that has been determined to be critical under the Endangered Species Act of 1973.

(10) Whether the action threatens a violation of Federal, State, or local law or requirements imposed for the protection of the environment.

Based upon a review of the EA and the associated documents referenced in the EA, and considering the criteria for significance provided by the CEQ regulations implementing the NEPA, I have determined that the Proposed Action (Alternative B) will not have a significant effect on the quality of the human environment, individually or cumulatively with other actions in the potentially affected areas. Therefore, an EIS will not be required in order to implement the Proposed Action (Alternative B) described in the EA. This finding is based on the context and intensity for the Proposed Action as described below:

Context

The Proposed Action is programmatic and would revise the existing regulatory requirements of 43 CFR part 3160, subpart 3162, and part 3170, subpart 3179, all of which apply to Federal and Indian (other than Osage Tribe) oil and gas leases, and replace them with requirements similar to those contained in Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A). The final rule addresses the routine flaring of associated gas by deferring to State or tribal regulations where possible and employing a standard, similar to the NTL-4A standard, for royalty-free flaring where no applicable State or tribal regulation exists. Although the Proposed Action is national in scope, its effects would primarily be felt in the West, where Federal and Indian oil and gas development is most prevalent.

Under the Proposed Action, the following regulatory provisions would be removed in their entirety:

- Waste Minimization Plan (§ 3162.3-1);
- Gas Capture Requirements (§ 3179.7);
- Alternative Capture Requirement (§ 3179.8);
- Other Waste Prevention Measures (§ 3179.11);
- Coordination with State Regulatory Authority (§ 3179.12);
- Well Drilling and Completions (§§ 3179.101 and 3179.102);
- Pneumatic Controllers and Pumps (§§ 3179.201 and 3179.202);
- Storage Vessels (§ 3179.203);
- Leak Detection and Repair (§§ 3179.301 to 3179.305); and
- State or Tribal Requests for Variances (§ 3179.401).

The following requirements in the 2016 rule would be modified and/or replaced with requirements that are similar to those that were in NTL-4A:

- Gas-capture requirements;
- Downhole well maintenance and liquids unloading requirements; and
- Measuring and reporting volumes of gas vented and flared.

The remaining requirements in the 2016 rule would either be retained, modified only slightly, or removed, but the impact of the change would be small relative to the items listed previously. See Appendix A of the EA for a section-by-section discussion of the Proposed Action.

Even though the BLM would not implement the 2016 rule requirements to capture additional natural gas, reduce the waste of natural gas from venting and flaring operations, or reduce leaks that may occur during oil and natural gas production activities on onshore Federal and Indian leases, the rule revision would not leave venting and flaring unregulated. States with the most significant BLM-managed oil and gas production currently have regulations in place that restrict or limit the waste of oil and gas resources and the flaring of natural gas. Summaries of these

State regulations can be found in the Regulatory Impact Analysis (RIA) for the Proposed Action (Section 2.8), as well as a separate Information Memorandum, both of which are available on www.regulations.gov. State laws and regulations apply on Federal lands, except when they are preempted by Federal law. If the requirement of a State regulation is more stringent than that of a Federal regulation, the operator would comply with both State and Federal requirements by meeting the more stringent State requirement. In addition, the EPA's New Source Performance Standards subparts OOOO and OOOOa regulate pneumatic controllers, storage tanks, gas wells completed using hydraulic fracturing, pneumatic pumps, fugitive emissions from well sites and compressor stations, and oil wells completed using hydraulic fracturing. Some tribes with oil and gas resources have also engaged in the regulation of venting and flaring on their lands. The Department of the Interior encourages tribes to exercise their sovereignty over their lands and mineral resources, which includes the regulation of venting and flaring operations. Finally, the BLM notes that, under the Proposed Action, the BLM would retain regulations imposing royalties on "avoidably lost" gas, thereby creating a financial incentive for operators to limit venting and flaring.

As described more fully in the EA, the BLM employs a tiered decision-making process when providing for the development of Federal oil and gas resources, and this process results in consideration of the environmental impacts of Federal oil and gas development at multiple stages. Specifically, the BLM takes steps to comply with NEPA, the Endangered Species Act, and the National Historic Preservation Act at the land use plan, lease sale, and application for permit to drill (APD) stages of development. At each stage, the BLM has an opportunity to impose appropriate restrictions on development as deemed necessary to protect the environment.

Intensity

1. *Impacts that may be both beneficial and adverse* - Due to the complex nature of the changes expected from the proposed action, the BLM anticipates both beneficial and adverse impacts to occur.

   The potential direct and indirect beneficial impacts of the Proposed Action are as follows:
   A. The BLM expects wildlife resources to benefit from a decrease in surface disturbance and habitat fragmentation expected to result from the accelerated development of gathering-line infrastructure in response to the 2016 rule's gas-capture requirements.
   B. The Proposed Action would also avoid the potential adverse impacts from increased truck traffic, the addition of flare devices to storage vessels, and the addition of compressor stations expected under the No Action Alternative.

   The potential direct and indirect adverse impacts of the Proposed Action are as follows:
   A. Forgone emissions reductions of 175,000 tons/year (TPY) of methane, 1,860

TPY of Hazardous Air Pollutants (HAP), and 80,000 TPY of Volatile Organic Compounds (VOC). The annual additional methane emissions associated with the Proposed Action are estimated to represent about 0.61 percent of the total U.S. methane emissions in 2015. Although the potential impacts of the proposed action in terms of greenhouse gas emissions are described here, the BLM notes that the actual effects of such emissions on global climate change, as well as the actual environmental effects attributable to the Proposed Action's impact on climate change, cannot be reliably assessed and thus are sufficiently uncertain as to be not reasonably foreseeable.

B. Additional flaring under the Proposed Action, thereby increasing noise and light pollution and potentially affecting the communities living near oil and gas development, wildlife, night-sky resources, and recreationists.

C. Adverse impacts on wildlife resources with respect to air quality and noise and light pollution. These impacts would result from increased venting and flaring relative to the baseline.

2. *The degree to which the Proposed Action affects public health or safety* - The Proposed Action is not expected to have a substantial adverse impact on public health or safety. Though the Proposed Action would result in forgone reductions in greenhouse gases, air pollutant, and HAP emissions, these emissions would be geographically dispersed and would, for the most part, occur in sparsely populated areas. The BLM will continue to examine site-specific public health concerns in developing resource management plans (RMPs) and when permitting oil and gas development at both the leasing and APD stages.

3. *Unique characteristics of the geographic area such as proximity to historic or cultural resources, park lands, prime farmlands, wetlands, wild and scenic rivers, or ecologically critical areas* - The Proposed Action is programmatic and is national in scope. The BLM will consider the relevant consequences of the Proposed Action when conducting site- specific reviews under NEPA, the National Historic Preservation Act (NHPA), and the Endangered Species Act (ESA). The Proposed Action is not expected to have a significant adverse effect on historic or cultural resources, park lands, prime farmlands, wetlands, wild and scenic rivers, or ecologically critical areas.

4. *The degree to which the effects on the quality of the human environment are likely to be highly controversial* - The expected environmental effect of the Proposed Action is to avoid the anticipated effects of the 2016 rule that were described in the 2016 EA. Although the 2016 rule has been the subject of litigation, the 2016 EA has not been challenged in court as failing to adequately and accurately consider the expected environmental effects of the 2016 rule. The EA for the Proposed Action closely followed the 2016 EA in describing the affected environment and the anticipated environmental effects of reversing the 2016 rule in terms of climate change, air quality, noise and light impacts, and impacts on wildlife resources, threatened and

endangered species, and critical habitat. The EA also explains that the BLM employs a tiered decision-making process when providing for the development of oil and gas resources and that the BLM will consider site-specific venting and flaring impacts when undertaking NEPA analyses at the RMP, leasing, and APD stages. Therefore, the BLM's analysis of the environmental effects of the reversal of the 2016 rule should not be in contention. The BLM does not believe that the effects of the Proposed Action on the quality of the human environment are likely to be highly controversial.

5. *The degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks* - Implementing the Proposed Action would not represent a situation that is unique or unusual. Prior to the issuance of the 2016 rule, the BLM regulated venting and flaring from oil and gas development on Federal and tribal lands under a regulatory regime similar to the Proposed Action. The potential environmental effects of the Proposed Action are adequately analyzed in the EA, and there are no reasonably foreseeable environmental effects that are considered to be highly uncertain or that involve unique or unknown risks.

6. *The degree to which the action may establish a precedent for future actions with significant effects or represents a decision in principle about a future consideration* - The Proposed Action does not establish a precedent for future actions with significant effects, nor does it represent a decision in principle about a future consideration. The Proposed Action revises the BLM's oil and gas operating regulations pertaining to the venting and flaring of gas during oil and gas production operations on BLM-administered leases. The Proposed Action deals specifically with the 2016 rule and would not establish a precedent for future rulemakings, as any future rules would be developed through a separate process. Furthermore, as explained in the EA, the BLM employs a tiered decision-making process when providing for the development of oil and gas resources. The BLM will consider site-specific venting and flaring impacts when undertaking NEPA analyses at the RMP, leasing, and APD stages, and the Proposed Action will not cabin or dictate the outcome of those considerations.

7. *Whether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts.* - The Proposed Action is not related to any other BLM actions with individually insignificant but cumulatively significant impacts. Where the impacts of future venting, flaring, or emissions from operations on Federal or Indian oil and gas leases may add to the impacts of pre-existing venting, flaring, or emissions, the cumulative significance of these impacts will be analyzed at a site-specific level, whether at the RMP, leasing, or APD stage.

8. *The degree to which the action may adversely affect districts, sites, highways, structures, or objects listed in or eligible for listing in the National Register of Historic Places or may cause loss or destruction of significant scientific, cultural, or historical resources* - The Proposed Action does not directly authorize actions that would affect scientific, cultural, or historical resources or districts, sites, highways, structures, or objects listed in or eligible for listing in the National Register of Historic Places. The BLM will consider the relevant consequences of the Proposed Action when conducting site-specific reviews under the NHPA, among other statutes. The Proposed Action is not expected to have a significant adverse effect on districts, sites, highways, structures, or objects listed in or eligible for listing in the National Register of Historic Places, nor is it expected to cause loss or destruction of significant scientific, cultural, or historical resources.

9. *The degree to which the action may adversely affect an endangered or threatened species or its habitat that has been determined to be critical under the ESA* - The Proposed Action does not directly authorize actions that would adversely affect an endangered or threatened species or its habitat that has been determined to be critical under the ESA. The Proposed Action is not expected to have a significant adverse effect on an endangered or threatened species or its habitat that has been determined to be critical under the ESA. The BLM developed a Biological Assessment and engaged in informal consultation with the Fish and Wildlife Service regarding the potential impacts of the Proposed Action on species and habitat. The Fish and Wildlife Service concluded that the BLM had met all of its obligations under the ESA with respect to the Proposed Action. The BLM will consider the relevant consequences of the Proposed Action when conducting site-specific reviews under the ESA, among other statutes.

10. *Whether the action threatens a violation of Federal, State, or local law or requirements imposed for the protection of the environment* - The Proposed Action does not threaten a violation of Federal, State, or local law. The Proposed Action does not authorize any entity to violate any statute or regulation, nor does it prevent any other governmental authorities from enforcing their statutes and regulations. The Proposed Action would revise certain regulations that are primarily concerned with the conservation of natural gas, rather than protection of the environment. Although the 2016 rule had secondary environmental benefits, the requirements of the 2016 rule were not imposed for the protection of the environment. Therefore, the Proposed Action does not threaten requirements imposed for the protection of the environment.

Determination

Based on the foregoing considerations and the analysis provided in the EA, I find that revising certain requirements imposed by the 2016 rule, as provided for in the Proposed Action (Alternative B) from the EA, would not have a significant effect on the quality of the human environment; therefore, an EIS is not required.

Michael D. Nedd

Assistant Director – Energy, Mineral and Realty Management

Bureau of Land Management

Date: September 14, 2018

Interior Department Finalizes New Waste Prevention Rule

The new rule re-establishes long-standing requirements and eliminates duplicative regulations that hurt states and Tribes

9/18/2018
Last edited 9/19/2018

Date: September 18, 2018

Contact: Interior_Press@ios.doi.gov

WASHINGTON – As part of the Trump Administration's ongoing goal to reduce the regulatory burden on the American people and foster economic growth and energy development by using innovation, best science, and best practices, the U.S. Department of the Interior's Bureau of Land Management (BLM) today announced a final rule that revises the 2016 Waste Prevention Rule (also known as the Venting and Flaring Rule). The new rule, which included a 60-day public comment period, will reduce unnecessary burdens on the private sector and restore proven regulations at a time when investment in Federal onshore oil and gas is skyrocketing.

"Sadly, the flawed 2016 rule was a radical assertion of legal authority that stood in stark contrast to the longstanding understanding of Interior's own lawyers," **said Deputy Secretary David Bernhardt**. "The Trump Administration is committed to innovative regulatory improvement and

environmental stewardship, while appropriately respecting the clear and distinct authorities of the States, Tribes, as well as the direction we receive from Congress."

The BLM reviewed the 2016 rule and found that it had considerable overlap in existing State, Tribal and Federal regulations. Additionally, the agency determined that the previous administration underestimated the cost in the 2016 rule.

The rule was reviewed as part of Executive Order 13771, Reducing Regulation and Controlling Regulatory Costs, Executive Order 13783, Promoting Energy Independence and Economic Growth, and Secretarial Order 3349, American Energy Independence, issued March 29, 2017. The BLM found that many parts of the 2016 rule were unnecessarily burdensome on the private sector.

Publication of the final rule in the Federal Register is forthcoming. The rule is effective 60 days after publication. A pre-publication version of the final rule can be found at https://go.usa.gov/xP2qE.

PRESS RELEASE

Secretary Zinke's Schedule October 1 - October 7

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PRESS RELEASE

4310-84P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 3160 and 3170

[18X.LLWO310000.L13100000.PP0000]

RIN 1004-AE53

Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rule.

SUMMARY: In this action, the Bureau of Land Management (BLM) is revising the November 18, 2016, rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" ("2016 rule") in a manner that reduces unnecessary compliance burdens, is consistent with the BLM's existing statutory authorities, and re-establishes longstanding requirements that had been replaced. The BLM is rescinding the 2016 rule's novel requirements pertaining to waste minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels, and leak detection and repair (LDAR). The BLM is revising the remaining provisions of the 2016 rule in a manner that largely reflects the BLM's longstanding policies for venting and flaring that preceded the 2016 rule. With respect to the flaring of associated gas from oil wells, the BLM will defer to appropriate State or tribal regulations in determining when such flaring will be royalty-free.

DATES: The final rule is effective on [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

FOR FURTHER INFORMATION CONTACT: Steven Wells, Division Chief, Fluid Minerals Division, 202-912-7143 or s1wells@blm.gov, for information regarding the substance of this final rule or information about the BLM's Fluid Minerals program. For questions relating to regulatory process issues, contact Faith Bremner at 202-912-7441 or fbremner@blm.gov. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service (FRS) at 1-800-877-8339, 24 hours a day, 7 days a week, to leave a message or question with the above individuals. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

On November 18, 2016, the BLM published in the *Federal Register* a final rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" (82 FR 83008) ("2016 rule"). The 2016 rule was intended to: Reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases; clarify when produced gas lost through venting, flaring, or leaks is subject to royalties; and clarify when oil and gas production may be used royalty-free on-site. The 2016 rule became effective on January 17, 2017,

with some requirements taking effect immediately, but the majority of requirements were to phase-in on January 17, 2018, or later.

On March 28, 2017, President Trump issued Executive Order (E.O.) 13783, “Promoting Energy Independence and Economic Growth,” directing the BLM to review the 2016 rule and, if appropriate, to publish proposed and final rules suspending, revising, or rescinding it.

The BLM reviewed the 2016 rule and found that certain impacts were underestimated and many provisions of the rule would have added regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation. The BLM also found that the 2016 rule’s approach to reduction of fugitive emissions and flaring departed from the historic approach of considering “waste” in the context of a reasonable and prudent operator standard. This final rule revises the 2016 rule in a manner that ensures consistency with the policies set forth in section 1 of E.O. 13783, which states that “[i]t is in the national interest to promote clean and safe development of our Nation’s vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.”

The BLM reviewed the 2016 rule and determined that it would have imposed costs exceeding its benefits. As detailed in the Regulatory Impact Analysis (RIA) prepared for this rule, and evidenced by the RIA prepared for the 2016 rule (2016 RIA), many of the provisions of the 2016 rule would have imposed compliance costs well in excess of the value of the resource (natural gas) that would have been conserved. In addition, the provisions of the 2016 rule, unlike the analogous Environmental Protection

Agency (EPA) regulations with which many of them overlapped, would have affected existing wells, including a substantial number that are “marginal,” or low-producing, and therefore less likely to remain economical to operate if subjected to additional compliance costs. The BLM estimates that approximately 73 percent of wells on BLM-administered leases would be considered marginal wells and that the annual compliance costs associated with the 2016 rule would have constituted 24 percent of an operator’s annual revenues from even the highest-producing marginal oil wells and 86 percent of an operator’s annual revenues from the highest-producing marginal gas wells. Finally, the BLM has determined that the 2016 rule also contains numerous administrative and reporting requirements that would have imposed unnecessary burdens on operators and the BLM. For these reasons, the BLM revised the 2016 rule in a manner that reduces unnecessary compliance burdens and, in large part, re-establishes the longstanding requirements that the 2016 rule replaced.

With this final rule, the BLM is discouraging excessive venting and flaring by placing volume and/or time limits on royalty-free venting and flaring during production testing, emergencies, and downhole well maintenance and liquids unloading. The BLM has also retained the 2016 rule’s subpart 3178 provisions, which incentivize the beneficial use of gas by making gas used for operations and production purposes royalty free. Finally, by rescinding the 2016 rule’s prescriptive requirements for pneumatic equipment, storage tanks, and LDAR—many of which were not cost-effective and risked the early shut-in of marginal wells—this final rule allows operators to continue implementing waste reduction strategies and programs that they find successful and to tailor or modify their programs in a manner that makes sense for their operations.

II. Background

A. Background

The BLM manages more than 245 million acres of public land, known as the National System of Public Lands, primarily located in 12 Western States, including Alaska. The BLM also manages 700 million acres of subsurface mineral estate throughout the nation.

The BLM's onshore oil and gas management program is a major contributor to the nation's oil and gas production. In fiscal year (FY) 2017, sales volumes from Federal onshore production lands accounted for approximately 9 percent of domestic natural gas production, 5 percent of U.S. natural gas liquids production, and 5 percent of domestically produced oil.[1] Roughly $1.9 billion in royalties were collected from all oil, natural gas, and natural gas liquids transactions in FY 2017 on Federal Lands.[2] Royalties from Federal lands are shared with States. Royalties from Indian lands are collected for the benefit of the Indian owners.

The venting or flaring of some natural gas is a practically unavoidable consequence of oil and gas development. Whether during well drilling, production testing, well purging, or emergencies, it is not uncommon for gas to reach the surface that cannot be feasibly captured, used, or sold. When this occurs, the gas must either be combusted ("flared") or released to the atmosphere ("vented"). Depending on the circumstances, operators may flare natural gas on a longer-term basis from production

[1] United States Department of the Interior, "Budget Justifications and Performance Integration Fiscal Year 2019: Bureau of Land Management" at VI-82, available at https://www.doi.gov/sites/doi.gov/files/uploads/fy2019_blm_budget_justification.pdf.
[2] Derived from data available on the Office of Natural Resources Revenue website's "Statistical Information" page, accessible at https://revenuedata.doi.gov/explore/.

operations, predominantly in situations where an oil well co-produces natural gas (or "associated gas") in an exploratory area or a field that lacks adequate gas-capture infrastructure to bring the gas to market. Production equipment may be designed to vent or flare gas, e.g., gas may be vented with the use of pneumatic controllers or combusted to generate power. Gas that accumulates in oil-storage tanks may also necessitate venting or flaring for safety. Finally, gas may be unintentionally lost through leaks from equipment and facilities.

In response to oversight reviews and a recognition of increased flaring from Federal and Indian leases, the BLM developed a final rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation," which was published in the *Federal Register* on November 18, 2016 (81 FR 83008) ("2016 rule"). The 2016 rule replaced the BLM's existing policy at that time, Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A) (44 FR 76600 (Dec. 27, 1979)).

The 2016 rule was intended to: Reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases; clarify when produced gas lost through venting, flaring or leaks is subject to royalties; and clarify when oil and gas production may be used royalty free on-site. The 2016 rule applied to all wells producing Federal and Indian oil and gas and regulated new, modified, and existing sources of methane emissions on Federal and Indian leases, units, and communitized areas. The 2016 rule became effective on January 17, 2017, with some requirements taking effect immediately, but the majority of requirements were to phase-in over time.

On March 28, 2017, President Trump issued E.O. 13783, entitled, “Promoting Energy Independence and Economic Growth,” directing the BLM to review the 2016 rule. Section 7(b) of E.O. 13783 directs the Secretary of the Interior to review four specific rules, including the 2016 rule, for consistency with the policy articulated in section 1 of the Order and, if appropriate, to publish rules suspending, revising, or rescinding those rules. Among other things, section 1 of E.O. 13783 states that “[i]t is in the national interest to promote clean and safe development of our Nation’s vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.”

To implement E.O. 13783, Secretary of the Interior Ryan Zinke issued Secretarial Order No. 3349, entitled, “American Energy Independence” on March 29, 2017, which, among other things, directs the BLM to review the 2016 rule to determine whether it is fully consistent with the policy set forth in section 1 of E.O. 13783.

The BLM reviewed the 2016 rule and determined it to be inconsistent with the policy in section 1 of E.O. 13783. The BLM found that some provisions of the 2016 rule would have added (once fully in effect) regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation. The BLM estimates that approximately 73 percent of wells on BLM-administered leases would be considered marginal wells and that the annual compliance costs associated with the 2016 rule would have constituted 24 percent of the annual revenues of even the highest-producing marginal oil wells and 86 percent of the annual revenues of the highest-producing marginal gas wells. The BLM also finds that marginal oil and gas production on Federal lands supported an estimated $2.9 billion in economic output in the national

economy in FY 2015. To the extent that the 2016 final rule would have adversely impacted production from marginal wells through premature shut-ins, this estimated economic output would have been jeopardized.

On February 22, 2018, the BLM published a proposal to revise the 2016 rule in a manner that would make it consistent with the policies set forth in section 1 of E.O. 13783. 83 FR 7924 (Feb. 22, 2018). The BLM provided for a 60-day public comment period, which generated more than 600,000 comments on the proposed rule. The BLM received comments from a wide variety of persons and entities, including individual citizens, environmental advocacy groups, industry advocacy groups, oil and gas exploration and production companies, public interest groups, state agencies, and tribes. The BLM has summarized and responded to these comments in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov. (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.) In addition, the BLM has noted the most salient comments on the proposed rule in its discussion of the final rule in this preamble. In response to comments and after further consideration, the BLM has made the following modifications to the proposed rule in this final rule: (1) Clarification that the 24-hour limit on royalty-free flaring during downhole well maintenance and liquids unloading in § 3179.104 applies "per event"; (2) Addition of a standard for "applicable rules, regulations, or orders" of a State regulatory agency or tribe in § 3179.201(a); and (3) Addition of a provision allowing for tribes to seek BLM approval to have tribal rules apply in place of any or all of the provisions of subpart 3179. The final rule is otherwise the same as the proposed rule.

The BLM has several compelling reasons for modifying the requirements in the 2016 rule.

First, the BLM believes that many provisions of the 2016 rule exceeded the BLM's statutory authority to regulate for the prevention of "waste" under the Mineral Leasing Act (MLA). The MLA states that all leases "shall be subject to the condition that the lessee will, in conducting his explorations and mining operations, use all reasonable precautions to prevent waste of oil or gas developed in the land . . . ."[3] The MLA further provides that "[e]ach lease shall contain provisions for the purpose of insuring the exercise of reasonable diligence, skill, and care in the operation of [the lease]," as well as "a provision that such rules . . . for the prevention of undue waste as may be prescribed by [the Secretary] shall be observed . . . ."[4] The concept of "waste" underlying the 2016 rule constituted a drastic departure from the concept of "waste" applied by the Department of the Interior over many decades of implementing the MLA. The 2016 rule was based on the premise that essentially any losses of gas at the production site could be regulated as "waste," without regard to the economics of conserving that lost gas. This is illustrated by the 2016 rule's "capture percentage," storage vessel, and LDAR requirements, all of which, as explained in more detail in the section-by-section analysis, were expected to impose compliance costs well in excess of the value of the gas to be conserved.

The Department's implementation of the MLA has long been informed by an understanding that there is a certain amount of unavoidable loss of oil and gas that is

[3] 30 U.S.C. 225. For convenience, where several statutes applicable to public lands support the same legal point, we refer hereinafter only to the MLA.
[4] 30 U.S.C. 187.

inherent in oil and gas production and, therefore, not all losses of gas may be considered "waste" under the MLA. *See Marathon Oil Co. v. Andrus*, 452 F. Supp. 548, 551 (D. Wyo. 1978) ("For more than half a century, both the government, as lessor, and all of its lessees have understood and have been governed by the pertinent statutes to the end that all oil and gas used on the lease for ordinary production purposes or unavoidably lost were not subject to royalty payments to the government."). Contrary to the novel interpretation of "waste" employed in the 2016 rule, the BLM has historically taken the lease-specific circumstances faced by an operator—including the economic viability of capturing and marketing the gas—into account before determining that a particular loss of gas constitutes "waste." *See Rife Oil Properties, Inc.*, 131 IBLA 357, 376 (1994) ("[T]he ultimate issue in this case is whether it would have been economic to market gas from the well at issue . . . ."); *Ladd Petroleum Corp.*, 107 IBLA 5 (1989) (remanding for "further consideration of whether it was uneconomic to capture that gas at that time").

In the 2016 rule, the BLM recognized the inconsistency with its longstanding practice, but argued that past practice did not prohibit the BLM from pursuing a different approach. *See* 81 FR 83038. However, in adopting an interpretation of "waste" that is not informed by the economics of capturing and marketing the gas, the BLM ignored the longstanding concept of "waste" in oil and gas law, which Congress adopted in enacting the MLA. Oil and gas law applies a "prudent operator" standard to oil and gas lessees, thereby imposing an obligation of reasonable diligence in the developing and marketing of oil and gas from the lease, with due regard for the interest of both the lessee and the lessor. *See, e.g., Brewster v. Lanyon Zinc Co.*, 140 F. 801, 814 (8th Cir. 1905) ("It is only to the end that the oil and gas shall be extracted with benefit or profit to both [lessee

and lessor] that reasonable diligence is required."); *see also* Patrick H. Martin & Bruce M. Kramer, WILLIAM & MEYERS OIL AND GAS LAW § 806.3 (abridged 4th edition) (2010). This prudent-operator standard was incorporated into the MLA through the provisions requiring lessees to exercise "reasonable diligence, skill, and care" in the operation of the lease, and subjecting leases to the condition that the lessee will "use all reasonable precautions to prevent waste of oil or gas developed in the land."[5] The exercise of "reasonable diligence" and employment of "reasonable precautions" do not require an operator to lose money capturing and marketing uneconomic gas. To require that operators do so, as the 2016 rule did, is inconsistent with the prudent-operator standard incorporated in the MLA and exceeds the BLM's waste-prevention authority. Although the 2016 rule contained provisions allowing operators to apply for exemptions or variances from many of the rule's requirements based on economic considerations, the standard for approving these variances or exemptions was not whether capturing and marketing the gas would be economic (i.e., whether capture would be expected of a prudent operator), but, rather, whether compliance would cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease.

The BLM's experience in the litigation of the 2016 rule reinforces the BLM's conclusion that the 2016 rule exceeded its statutory authority. Immediately after the 2016 rule was issued, petitions for judicial review of the rule were filed by industry groups and States with significant BLM-managed Federal and Indian minerals. *Wyoming v. U.S. Dep't of the Interior*, Case No. 2:16-cv-00285-SWS (D. Wyo.). Petitioners in this litigation argued that the BLM exceeded its statutory authority by promulgating a rule

[5] 30 U.S.C. 187, 225.

that, rather than regulating for the prevention of "waste," was actually intended to regulate air quality, a matter within the regulatory jurisdiction of the EPA and the States under the Clean Air Act. Petitioners also argued that the 2016 rule exceeded the BLM's waste-prevention authority by requiring conservation without regard to economic feasibility, a key factor in determining whether a loss of oil or gas is prohibited "waste" under the MLA. Although the court denied petitioners' motions for a preliminary injunction, the court did very clearly express grave concerns that the BLM had usurped the authority of the EPA and the States under the Clean Air Act, and questioned whether it was appropriate for the 2016 rule to be justified based on its environmental and societal benefits, rather than on its resource conservation benefits alone. *Wyoming v. U.S. Dep't of the Interior*, 2017 WL 161428, *6-10 (D. Wyo.) (Jan. 16, 2017). The BLM has considered the court's concerns with the 2016 rule and finds them to be valid. In its revision of the 2016 rule, the BLM has sought to ensure that its regulations are justified as waste-prevention measures under the BLM's MLA authority and do not usurp the Clean Air Act authority of the EPA, the States, and tribes. To achieve this end, the BLM is rescinding the provisions of the 2016 rule that imposed costs in excess of their resource conservation benefits or created the potential for impermissible conflict with the regulation of air quality by the EPA or the States under the Clean Air Act. The BLM acknowledges that, because regulations that prevent wasteful losses of natural gas necessarily reduce emissions of that gas, there is some limited degree of overlap between the BLM's MLA authority and the Clean Air Act authority of the EPA, the States, and tribes. However, in the words of the court, "the BLM cannot use overlap to justify overreach." *Wyoming*, 2017 WL 161428, *9.

Second, the BLM reviewed the 2016 rule's requirements and determined that the rule's compliance costs for industry and implementation costs for the BLM exceed the rule's benefits. Over the 10-year evaluation period (2019-2028), the total net benefits from the 2016 rule are estimated to be -$736 million to -$1.01 billion (net present value (NPV) and interim domestic social cost of methane (SC-CH_4) using a 7 percent discount rate) or -$722 million to -$1.09 billion (NPV and interim domestic SC-CH_4 using a 3 percent discount rate). For a more detailed explanation, see the analysis of the 2016 rule's requirements (baseline scenario) in the Regulatory Impact Analysis (RIA) prepared for this rule (RIA at Section 4.3). Although the 2016 RIA found that overall benefits of the 2016 rule would exceed its costs, this finding was dependent upon the use of a "global" social cost of methane metric based on Technical Support Documents that have since been rescinded. As described in more detail below, BLM's cost-benefit analysis for this revision of the 2016 rule followed longstanding guidance in Office of Management and Budget Circular A-4 (Sept. 17, 2003).

In addition, many of the 2016 rule's requirements placed a particular compliance burden on operators of marginal or low-producing wells, and there is a substantial risk that many of these wells would not be economical to operate with the additional compliance costs. Although the characteristics of what is considered to be a marginal well can vary, the percentage of the nation's oil and gas wells classified as marginal is high. The Interstate Oil and Gas Compact Commission (IOGCC) published a report in 2015 detailing the contributions of marginal wells to the nation's oil and gas production

and economic activity.[6] According to the IOGCC, about 69.1 percent and 75.9 percent of the nation's operating oil and gas wells, respectively, are marginal (IOGCC 2015 at 22). The IOGCC defines a marginal well as "a well that produces 10 barrels of oil or 60 Mcf of natural gas per day or less" (IOGCC 2015 at 2).[7] The U.S. Energy Information Administration (EIA) reported that, in 2016, roughly 76.4 percent of oil wells produced less than or equal to 10 barrels of oil equivalent (BOE) per day and 81.3 percent of oil wells produced less than or equal to 15 BOE/day. For gas wells, EIA reported that roughly 71.6 percent produced less than or equal to 10 BOE/day and 78.2 percent less than or equal to 15 BOE/day. For both oil and gas wells, EIA estimates that 73.3 percent of all wells produce less than 10 BOE/day.[8] Applying these estimates to the overall number of BLM-administered wells indicates that about 69,000 wells producing Federal and/or Indian oil and gas are marginal.[9]

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[6] IOGCC, "Marginal Wells: Fuel for Economic Growth. 2015 Report." Available on the web at http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/MarginalWell-2015.pdf.

[7] By other definitions, marginal or stripper wells might include those with production of up to 15 barrels of oil or 90 Mcf of natural gas per day or less. The U.S. Energy Information Administration (EIA) reported that, in 2009, roughly 78.7 percent of oil wells produced less than or equal to 10 barrels of oil equivalent (BOE) per day and 85.4 percent of oil wells produced less than or equal to 15 BOE/day. For gas wells, EIA reported that roughly 64.5 percent produced less than or equal to 10 BOE/day and 73.3 percent less than or equal to 15 BOE/day. EIA, "United States Total 2009: Distribution of Wells by Production Rate Bracket." December 2010. Available on the web at https://www.eia.gov/naturalgas/archive/petrosystem/us_table.html.

[8] EIA, "The Distribution of U.S. Oil and Natural Gas Wells by Production Rate." December 2017. Available on the web at https://www.eia.gov/petroleum/wells/, Table B17. United States oil and gas well summary statistics, 2016.

[9] The BLM obtained this number by estimating the percent of marginal wells and by multiplying that percentage by the number of Federal and Indian wells reported in the BLM Oil and Gas Statistics, *available at* https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics. The BLM is not aware of any information indicating that the incidence of marginal wells producing Federal and Indian oil and gas is substantially different than the incidence of marginal wells nationally, and so it is appropriate to use the EIA's estimate of the national incidence of marginal wells in estimating the number of marginal wells producing Federal and Indian oil and gas. The BLM's estimate is further supported by comments that the American Petroleum Institute (API) submitted to the BLM's proposed rule. The API estimates that between 70 percent and 80 percent of the Federal and Indian wells that would have been impacted by the 2016 rule are marginal. See API comment at Appendix A, p. 3.

The 2016 rule's requirements that would have placed a particular burden on marginal wells were those pertaining to pneumatic controllers, pneumatic diaphragm pumps, and LDAR. To illustrate the impact on the economic viability of marginal oil and gas wells from the 2016 rule, the BLM calculated the per-well reduction in revenue from the costs imposed by the requirements in the 2016 rule. The reduction in revenue was calculated using both total and annualized costs at three different periods in EIA's 2018 Annual Energy Outlook (AEO) price forecast. The per-well revenue values are the product of estimated annual production and annual average prices less royalty payments and lifting costs. Based on EIA's projected 2019 prices, the estimated revenue reduction for marginal oil wells ranges from 24 percent for wells producing 10 bbl/day to 236 percent for wells producing 1 bbl/day. Revenue reductions to marginal gas wells range from 86 percent for wells producing 60 mcf/day to 1,037 percent for wells producing 5 mcf/day. These values are reduced when using annualized costs, however, the reductions in revenue are still substantial. Production from marginal wells represents a smaller fraction of total oil and gas production than that of non-marginal wells. However, as the BLM's analysis indicates, this means that any associated regulatory burdens would have a disproportionate impact on marginal wells, since the compliance costs represent a much higher fraction of oil and gas revenues for marginal wells than they do for non-marginal wells. Thus, the compliance burdens of the 2016 rule pose a greater cost to marginal-well producers. The BLM's analysis of the impact of the 2016 rule on marginal wells is explained in more detail in Section 4.5.6 of the RIA.

The 2016 rule attempted to address the marginal-well problem by providing operators with an opportunity to obtain exemptions from many of the most costly

requirements when compliance would impose such costs that an operator would cease production and abandon significant recoverable reserves. Although the 2016 rule allowed operators to request an alternative LDAR program based on these considerations, there was no opportunity for a full exemption from the LDAR requirement in the 2016 rule.[10] Moreover, it was not clear what would constitute significant recoverable reserves for purposes of determining whether an operator would qualify for an exemption or an alternative LDAR program. In light of the fact that compliance costs for the 2016 rule represent 24 percent of the revenues of the highest-producing marginal oil wells and 86 percent of the revenues of the highest-producing marginal gas wells, the BLM expects that full compliance with the 2016 rule could have jeopardized the economic operations of many marginal wells and that many applications for exemptions or alternative LDAR programs would have been warranted. And, due to the prevalence of marginal and low-producing wells, the BLM expects that the burden imposed by the exemption/alternative processes would have been excessive, both for operators and the BLM. An operator would incur costs in obtaining an exemption or approval for an alternative LDAR program, as the operator would need to submit an application with economic and geologic information and analysis proving to BLM's satisfaction that compliance would cause the operator to cease production and abandon significant recoverable reserves. Considering this cost in light of the fact that the standard for obtaining an exemption or approval for an alternative LDAR program is unclear and subject to interpretation, the BLM believes that the costs and uncertainties involved in processes for receiving an

[10] The BLM estimates that, over 10 years from 2019-2028, the 2016 rule's LDAR requirements would have imposed costs of about $550 million to $688 million while only generating cost savings from product recovery of about $101 million to $128 million (RIA at Section 4.4).

exemption or approval for an alternative LDAR program could have led the operators of the lowest-producing marginal wells to shut them in prematurely, stranding otherwise recoverable resources in place.

In addition to the costs of complying with the 2016 rule's operational requirements, there were many reporting requirements in the 2016 rule and the cumulative effect of the burden would have been substantial. Specifically, the BLM estimates that the 2016 rule would have imposed administrative costs of about $14 million per year ($10.7 million to be borne by the industry and $3.27 million to be borne by the BLM). The BLM estimates that this final rule will alleviate the vast majority of these burdens and will pose administrative burdens of only $349,000 per year. (See RIA Section 3.2.2).

Beyond the cost-benefit analysis, the impact to marginal wells, and the reporting burdens, the BLM notes that the 2016 rule had many requirements that overlapped with the EPA's regulations issued under the Clean Air Act, namely EPA's New Source Performance Standards (NSPS) at 40 CFR part 60, subparts OOOO (NSPS OOOO) and OOOOa (NSPS OOOOa). The EPA's NSPS OOOO regulates new, reconstructed, and modified pneumatic controllers, storage tanks, and gas wells completed using hydraulic fracturing, while NSPS OOOOa regulates new, reconstructed, and modified pneumatic pumps, fugitive emissions from well sites and compressor stations, and oil and gas wells completed using hydraulic fracturing. The BLM's 2016 rule also would have regulated emissions of natural gas from these source categories. While the EPA regulates new, modified, and reconstructed sources, the BLM's 2016 rule applied to all wells and facilities producing Federal and Indian oil and gas and regulated emissions from new,

modified, and existing sources. The 2016 rule's emissions-targeting provisions were informed by and were largely similar to EPA's requirements for the same sources of emissions. Therefore, the practical effect of the 2016 rule's emissions-targeting provisions was essentially to impose EPA requirements designed for new and reconstructed sources on existing sources producing Federal and Indian oil and gas.[11]

In addition, as the BLM acknowledged during the development of the 2016 rule,[12] some States with significant Federal oil and gas production have similar regulations addressing the loss of gas from these sources. For example, the State of Colorado has regulations that restrict hydrocarbon emissions during most oil and gas well completions and recompletions, impose requirements for pneumatic controllers and storage vessels, require a comprehensive LDAR program, and set standards for liquids unloading.[13] In addition, the Utah Department of Environmental Quality has issued regulations addressing emissions from pneumatic controllers and storage vessels as well as fugitive emissions from oil and gas wellsites.[14] Since the promulgation of the 2016 rule, the State of California has also issued new regulations that: Require quarterly monitoring of methane emissions from oil and gas wells, compressor stations and other equipment involved in the production of oil and gas; impose limitations on venting from natural-gas-powered pneumatic devices and pumps; and require vapor recovery from tanks under

[11] The EPA can regulate existing facilities through a process separate from how it regulates new, modified, and reconstructed sources. Challengers of the 2016 rule argued that the BLM circumvented that EPA process by promulgating the 2016 rule.
[12] 81 FR 6616, 6633-34 (Feb. 8, 2016).
[13] Colorado Air Quality Control Commission, Regulation 7, 5 CCR 1001-9, Sections XII, XVII, and XVIII.
[14] UTAH ADMIN. CODE r.307-501–510.

certain circumstances.[15] The existence of methane emissions regulations in these states highlights the unnecessary regulatory overlap and duplication created by the 2016 rule.

Finally, the 2016 rule also had requirements that limited the flaring of associated gas produced from oil wells. The 2016 rule sought to constrain the flaring of associated gas through the imposition of a "capture percentage" requirement, which required operators to capture a certain percentage of the gas they produce, after allowing for a certain volume of flaring per well. The requirement would have become more stringent over a period of years. As explained below, the BLM has chosen to rescind this requirement in favor of an approach that relies on State and tribal regulations and reinstates the NTL-4A standard for flaring in the absence of applicable State or tribal regulations. The BLM reviewed State regulations, rules, and orders designed to limit the waste of oil and gas resources and the flaring of natural gas, and determined that States with the most significant BLM-managed oil and gas production place restrictions or limitations on gas flaring from oil wells. For example, the State of North Dakota has requirements that are similar (but not identical) to the 2016 rule. Other States generally have flaring limits that trigger a review by a governing board to determine whether the gas should be conserved. A memorandum containing a summary of the statutory and regulatory restrictions on venting and flaring in the 10 States responsible for approximately 99 percent of Federal oil and gas production is available on the *Federal eRulemaking Portal*: https://www.regulations.gov. In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.

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[15] CAL. CODE REGS. Tit. 17, §§ 95665–95677.

B. Legal Authority

Pursuant to a delegation of Secretarial authority, the BLM regulates the development of Federal and Indian onshore oil and gas resources under the following statutes: The Mineral Leasing Act of 1920 (MLA) (30 U.S.C. 188-287), the Mineral Leasing Act for Acquired Lands (MLAAL) (30 U.S.C. 351-360), the Federal Oil and Gas Royalty Management Act (30 U.S.C. 1701-1758), the Federal Land Policy and Management Act of 1976 (FLPMA) (43 U.S.C. 1701-1785), the Indian Mineral Leasing Act of 1938 (IMLA) (25 U.S.C. 396a-g), the Indian Mineral Development Act of 1982 (IMDA) (25 U.S.C. 2101-2108), the Act of March 3, 1909 (25 U.S.C. 396), and the other statutes and authorities listed in 43 CFR 3160.0-3. These statutes authorize the Secretary of the Interior to promulgate such rules and regulations as may be necessary to carry out the statutes' various purposes.[16] Although the MLA authorizes the Secretary to prescribe rules and regulations for carrying out the purposes of the MLA, it also states that "nothing in [the MLA] shall be construed or held to affect the rights of the States or other local authority to exercise any rights which they may have."[17]

The Federal mineral leasing statutes share a common purpose of promoting the development of Federal oil and gas resources for the financial benefit of the public.[18] The MLA states that all leases "shall be subject to the condition that the lessee will, in conducting his explorations and mining operations, use all reasonable precautions to

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[16] E.g., 30 U.S.C. 189 (MLA); 30 U.S.C. 359 (MLAAL); 30 U.S.C. 1751(a) (FOGRMA); 43 U.S.C. 1740 (FLPMA); 25 U.S.C. 396d (IMLA); 25 U.S.C. 2107 (IMDA); 25 U.S.C. 396.
[17] 30 U.S.C. 189.
[18] *See, e.g., California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961) (noting that the MLA "was intended to promote wise development of . . . natural resources and to obtain for the public a reasonable financial return on assets that 'belong' to the public.").

prevent waste of oil or gas developed in the land . . . ."[19] The MLA further provides that "[e]ach lease shall contain . . . a provision that such rules . . . for the prevention of undue waste as may be prescribed by [the Secretary] shall be observed . . . ."[20] FOGRMA establishes royalty liability for "oil or gas lost or wasted . . . when such loss or waste is due to negligence on the part of the operator of the lease, or due to the failure to comply with any rule or regulation, order or citation issued under [the mineral leasing laws]."[21] In FLPMA, Congress declared "that it is the policy of the United States that . . . the public lands be managed in a manner which recognizes the Nation's need for domestic sources of minerals . . . ."[22]

The Indian minerals statutes require the Secretary to exercise his trust responsibilities in the best interests of the tribes or of the individual Indian mineral owners, considering all factors affecting their interests. E.g., Kenai Oil & Gas, Inc. v. DOI, 671 F.2d 383, 387 (10th Cir. 1982).

To assure that the development of Federal and Indian oil and gas resources will not be unnecessarily hindered by regulatory burdens, the BLM has, in this rulemaking, exercised its inherent authority[23] to reconsider the 2016 rule. The BLM's revision of the 2016 rule is intended to ensure that, consistent with its statutory authority, the BLM's waste prevention regulations target "undue waste" and require "reasonable precautions"

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[19] 30 U.S.C. 225. For convenience, where several statutes applicable to public lands support the same legal point, we refer hereinafter only to the MLA.
[20] 30 U.S.C. 187.
[21] 30 U.S.C. 1756.
[22] 43 U.S.C. 1701.
[23] *See Ivy Sports Med., LLC v. Burwell*, 767 F.3d 81, 86 (D.C. Cir. 2014) (noting the "oft-repeated" principle that the "power to reconsider is inherent in the power to decide").

on the part of operators, and that the BLM's regulations do not unnecessarily constrain domestic mineral production or oil and gas revenues from Indian lands.

The BLM received a number of comments addressing its statutory authority and obligations. The BLM did not make any changes to the rule based on these comments.

Some commenters argued that the 2016 rule exceeded the BLM's statutory authority and alleged that BLM was attempting to regulate air quality under the guise of waste prevention. These commenters argued that the authority to regulate air quality at oil and gas operations rests with the EPA and the States, not with the BLM. As evidence of the alleged overreach, these commenters cited a number of "air quality" provisions in the 2016 rule for which compliance costs outweighed conservation benefits. These commenters expressed support for the BLM's revision of the 2016 rule on the grounds that the revision brings the BLM's regulations back in line with its statutory authority.

Other commenters argued that the BLM's proposed revision of the 2016 rule would fail to meet what they saw as the BLM obligations under the MLA. They argued that the proposed revision of the 2016 rule would not require operators to use "all reasonable precautions to prevent waste" and would not prevent "undue waste." They further argued that the BLM's policy determination that waste-prevention regulations should balance compliance costs against conservation benefits (i.e., the value of the resource to be conserved) is inconsistent with the concept of "waste" in the MLA. Ultimately, however, these commenters failed to provide legal authorities or evidence sufficient to persuade the BLM that the MLA either does not provide the BLM with the discretion to determine what constitutes "reasonable precautions" and "undue waste," or that the BLM's revision of the 2016 rule exceeds the BLM's discretion in this area.

Some commenters noted that the BLM gave less emphasis to operator economics in developing the 2016 rule. As explained above, the BLM believes that, by failing to give due regard to operator economics, the BLM exceeded its statutory authority in imposing many of the 2016 rule's requirements. The BLM's revision of the 2016 rule is consistent with the MLA and is consistent with the BLM's longstanding approach to regulating waste prior to the promulgation of the 2016 rule that considered the economic feasibility of marketing lost gas in making "avoidable loss" determinations. *See Rife Oil Properties, Inc.*, 131 IBLA 357, 373–76 (1994); *Ladd Petro. Corp.*, 107 IBLA 5, 7 (1989). And, even if the 2016 rule did not exceed the BLM's statutory authority, it is nonetheless within the BLM's authority to revise its "waste prevention" regulations in a manner that balances compliance costs against the value of the resources to be conserved.

Some commenters argued that the BLM's revision of the 2016 rule violates FLPMA because FLPMA states that the Secretary "shall manage the public lands under principles of multiple use and sustained yield" and that the Secretary "shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the public lands." 43 U.S.C. 1732(a)-(b). The BLM acknowledges the quoted mandates of FLPMA, but disagrees that they support the commenters' conclusion. FLPMA's concern with "unnecessary or undue degradation" must be understood in light of the statute's overarching mandate that the BLM manage the public lands under "principles of multiple use and sustained yield." *See* Theodore Roosevelt Conservation P'ship v. Salazar, 661 F.3d 66, 76 (D.C. Cir. 2011). FLPMA's multiple-use and sustained-yield mandate requires the BLM to balance potentially degrading uses, such as mineral extraction, with conservation of the natural environment so as to ensure valuable uses of

the lands in the future. *Id.* Nothing in the revision of the rule precludes the BLM from managing the development of Federal oil and gas—a statutorily authorized use of the public lands—in accordance with the principles of multiple use and sustained yield and requiring the avoidance and minimization of impacts where appropriate. Commenters highlighted the noise, light, and air quality impacts expected to be associated with the revised regulations, but they failed to explain why it would be impossible for the BLM to balance these impacts with appropriate conservation measures as needed in order to comply with FLPMA. The BLM considers the environmental impacts of oil and gas production in complying with the National Environmental Policy Act at the resource management planning, lease sale, and well permitting stages of Federal oil and gas development, and the BLM may identify appropriate region- and site-specific environmental-impact avoidance and minimization measures at each of those stages. Commenters, therefore, failed to convince the BLM that its revision of the 2016 rule is inconsistent with FLPMA.

III. Discussion of the Final Rule

A. Summary

The 2016 rule replaced the BLM's prior policy, NTL-4A, which governed venting and flaring from BLM-administered leases for more than 35 years. Because the BLM has found the 2016 rule would impose excessive costs (when fully implemented), and believes that a regulatory framework similar to NTL-4A can be applied in a manner that limits waste without unnecessarily burdening production, the BLM has replaced the requirements contained in the 2016 rule with requirements similar to, but with notable improvements on, those contained in NTL-4A.

The preamble to the 2016 rule suggested that NTL-4A was outdated and needed to be overhauled to account for technological advancements and to incorporate "economical, cost-effective, and reasonable measures that operators can take to minimize gas waste."[24] But, as evidenced by the 2016 RIA and the RIA prepared for this final rule, many of the requirements imposed by the 2016 rule were not, in fact, cost-effective and actually imposed compliance costs well in excess of the value of the resource to be conserved. The BLM believes that a return to an improved NTL-4A framework, as explained in more detail in the section-by-section discussion below, is appropriate and will ensure that operators take "reasonable precautions" to prevent "undue waste." Notable improvements on NTL-4A in this final rule include: Codifying a general requirement that operators flare, rather than vent, gas that is not captured (§ 3179.6); requiring persons conducting manual well purging to remain onsite in order to end the venting event as soon as practical (§ 3179.104); and, providing clarity about what does and does not constitute an "emergency" for the purposes of royalty assessment (§ 3179.103).

With this final rule, the BLM has rescinded the following requirements of the 2016 rule:

- Waste Minimization Plans;
- Well drilling requirements;
- Well completion and related operations requirements;
- Pneumatic controllers equipment requirements;
- Pneumatic diaphragm pumps equipment requirements;

[24] 81 FR 83008, 83009, 83017 (Nov. 18, 2016).

- Storage vessels equipment requirements; and
- LDAR requirements.

In addition, the BLM has modified and/or replaced the following requirements of the 2016 rule with requirements that are similar to those that were in NTL-4A:

- Gas-capture requirements;
- Downhole well maintenance and liquids unloading requirements; and
- Measuring and reporting volumes of gas vented and flared.

The remaining requirements in the 2016 rule have either been retained, modified only slightly, or removed, but the impact of the removal is small relative to the items listed above.

Many of the rescinded provisions of the 2016 rule focused on controlling emissions from sources and operations, which are regulated by EPA under its Clean Air Act authority, and for which there are analogous EPA regulations at 40 CFR part 60, subparts OOOO and OOOOa. Specifically, these emissions-targeting provisions of the 2016 rule are §§ 3179.102, 3179.201, 3179.202, 3179.203, and 3179.301 through 3179.305. The BLM has chosen to rescind these provisions based on a number of considerations.

First, the BLM has reconsidered whether the substantial compliance costs associated with the emissions-targeting provisions are justified by the value of the gas that is expected to be conserved as a result of compliance. As detailed in the RIA, and evidenced by the 2016 RIA, many of the emissions-targeting provisions of the 2016 rule were expected to impose compliance costs well in excess of the value of the resource (natural gas) that would be conserved. The BLM has made the policy determination that

it is not appropriate for “waste prevention” regulations to impose compliance costs greater than the value of the resources they are expected to conserve. Although the RIA for the 2016 rule found that, in total, the benefits of these provisions outweighed their costs, this finding depended on the use of a global social cost of methane (SC-CH_4) metric derived from Technical Support Documents which have since been rescinded. The SC-CH_4 metric is a societal metric that does not inform the “prevention of undue waste” or “reasonable precautions to prevent waste” under the MLA, which is statutory language that the BLM interprets in terms of the conservation of oil and gas resources. Although the BLM has employed the SC-CH_4 metric for the purpose of examining and disclosing the impacts of this regulatory action pursuant to E.O. 12866, it is not appropriate for the BLM to use the SC-CH_4 metric when determining whether a loss of natural gas is “waste” under the MLA.

E.O. 13783, at Section 5, disbanded the earlier Interagency Working Group on Social Cost of Greenhouse Gases (IWG) and withdrew the Technical Support Documents[25] upon which the RIA for the 2016 rule relied for the valuation of changes in methane emissions. The SC-CH_4 estimates presented by the BLM for this revision rule are interim values for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S. can be developed. In accordance with E.O. 13783, they are adjusted to reflect discount rates of 3 percent and 7 percent, and to focus on domestic—rather than global—impacts of climate change, which is consistent with OMB Circular A-4. The 7 percent rate is intended to represent the average before-tax rate of

[25] Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under E.O. 12866 (published August 26, 2016) and its Addendum.

return to private capital in the U.S. economy. The 3 percent rate is intended to reflect the rate at which society discounts future consumption, which is particularly relevant if a regulation is expected to affect private consumption directly. When assessing domestic impacts of climate change, the benefits of many of the emissions-targeting provisions do not outweigh their costs. And, because the value of the conserved gas would not outweigh the costs, the BLM does not believe that its legal authority to prescribe rules "for the prevention of undue waste"[26] would cover the emissions-targeting provisions in the 2016 rule.

Several commenters argued that the SC-CH_4 approach taken in the economic analysis for the revision of the 2016 rule fails to adequately recognize the global nature of methane emissions impacts. These commenters asserted that the U.S. will likely be forced to increase humanitarian aid, deal with mass migrations, and manage changing security needs (e.g., in the Arctic) as a result of overseas climate change impacts. They further argued that overseas impacts could also affect the U.S. economy, disrupting international trade and undermining financial markets. In response, the BLM reiterates that the Technical Support Documents that provided the basis for the use of the global social cost of methane in the 2016 RIA were rescinded by EO 13783 and that the BLM followed the guidance in OMB Circular A-4 in conducting its economic analysis of the anticipated climate impacts of this rule.[27] Finally, the BLM notes that its use of this same domestic social cost of methane analysis in a rulemaking to temporarily suspend certain provisions of the 2016 rule was recently examined by a U.S. District Court in the context of a preliminary injunction motion and that court found the BLM's social cost of methane

[26] 30 U.S.C. 187.

[27] See the RIA at Section 3.3 for a discussion of how the BLM's analysis is consistent with Circular A-4.

analysis to be acceptable. *California v. BLM*, 286 F.Supp.3d 1054, 1070 (N.D. Cal. 2018) ("[BLM] has provided a factual basis for its change in position (the OMB circular and Executive Order 13793) as well as demonstrated that the change is within its discretion, at least with respect to this aspect of the RIA").

In addition to cost-benefit concerns, the BLM believes that the emissions-targeting provisions of the 2016 rule create unnecessary regulatory overlap in light of EPA's Clean Air Act authority and its analogous regulations that similarly reduce losses of gas.[28] In general, the emissions-targeting provisions of the 2016 rule were crafted so that compliance with similar provisions within EPA's regulations would constitute compliance with the BLM's regulations. Although EPA's regulations apply to new, reconstructed, and modified sources, while the 2016 rule's requirements also applied to existing sources, the BLM notes that the EPA's regulations at 40 CFR part 60 subpart OOOO[29] were published in 2012 and that over time, as existing well sites are modified or reconstructed and new well sites come online, the EPA's regulations at 40 CFR part 60 subparts OOOO and OOOOa will displace the BLM's regulations, eventually rendering certain emissions-targeting provisions of the 2016 rule entirely duplicative. The rate by which we expect the EPA's regulations to become entirely duplicative of the 2016 rule varies by requirement and the specific equipment or operations being regulated. For example, assuming a pneumatic controller equipment life of 15 years, we would expect the EPA's subpart OOOO regulations to entirely duplicate the 2016 rule in 8 years (or by 2026) since those requirements have been in effect for 7 years. With respect to LDAR,

[28] The BLM is aware that the EPA has proposed a temporary stay of some of the requirements contained in NSPS OOOOa and that the EPA is undertaking a reconsideration of these requirements. See 82 FR 27645 (June 16, 2017). The BLM has coordinated with the EPA throughout the process of revising the 2016 rule.
[29] Subpart OOOO was finalized in 2012, but covers new, modified, reconstructed sources since 2011.

an existing well would fall under EPA's subpart OOOOa regulations if any of the existing wells on the wellsite are modified or reconstructed, or if a new well is added to the wellsite. Therefore, existing wells might shift quickly from the 2016 rule to EPA's subpart OOOOa regulation (e.g., if multiple existing wells shift to the EPA's regulations due to the modification of a single well on the wellsite) or not at all (e.g., if a well or wellsite is never modified before being plugged and abandoned). By removing the duplicative emissions-targeting provisions, the final rule falls squarely within the scope of the BLM's authority to prevent waste and leaves the regulation of air emissions to the EPA, the agency with the experience, expertise, and clear statutory authority to do so.

The BLM received comments asserting that the BLM cannot rely on EPA's regulations to reduce waste from oil and gas operations on Federal and Indian leases for a variety of reasons, including that EPA's regulations do not apply to existing sources, that the EPA does not regulate for the purpose of preventing waste, and that the BLM has not quantified the extent to which EPA's regulations will reduce waste from Federal and Indian oil and gas operations in the time period before EPA's regulations entirely displace the 2016 rule's requirements. These comments are based on an incorrect belief that the BLM is relying on EPA regulations to limit waste. As discussed above, the BLM has found that many of the emissions-targeting provisions of the 2016 rule do not target waste because their compliance costs far exceed the value of the resource to be conserved. Even if the BLM were relying on EPA's regulations to address waste from these sources and operations – which it is not – this would be consistent with the 2016

rule, which provided exemptions for sources and operations compliant with or subject to analogous EPA regulations.[30]

Finally, the BLM recognizes that the oil and gas exploration and production industry continues to pursue reductions in methane emissions on a voluntary basis. For example, XTO Energy, Inc., which operates 2,572 BLM-administered leases and agreements, has publicly stated that it is undertaking a 3-year plan to phase out high-bleed pneumatic devices from its operations and will be implementing an enhanced LDAR program.[31] In December 2017, the American Petroleum Institute (API) announced a voluntary program to reduce methane emissions. The API announced that 26 companies, including ExxonMobil, Chevron, Shell, Anadarko and EOG Resources, would take action to implement LDAR programs and replace, remove, or retrofit high-bleed pneumatic controllers with low- or zero-emitting devices.[32]

With this final rule, the BLM did not revise the royalty provisions (43 CFR 3103.3-1) or the royalty-free use provisions (43 CFR subpart 3178) that were part of the 2016 rule. Although the BLM sought and received comments on the royalty-free use provisions in subpart 3178, the BLM was not persuaded that any amendment of subpart 3178 is necessary at this time.

The BLM intends that each of the provisions of the final rule is severable. It is reasonable to consider the provisions severable because they do not inextricably depend

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[30] See former 43 CFR 3179.102(b), 3179.201(a)(2), 3179.202(a)(2), 3179.203(a)(2), 3179.301(k).
[31] XTO Energy, "Methane emissions reduction program", *available at* https://www.xtoenergy.com/en-us/responsibility/current-issues/air/xto-energy-methane-emissions-reduction-program
[32] Osborne, J., "Oil companies clamping down on methane leaks," *Houston Chronicle* (Dec. 6, 2017); American Petroleum Institute, "Natural Gas, Oil Industry Launch Environmental Partnership to Accelerate Reductions in Methane, VOCs," *available at* http://www.api.org/news-policy-and-issues/news/2017/12/04/natural-gas-oil-environmental-partnership-accelerate-reductions-methane-vocs.

on each other. For example, revised § 3179.4, which specifies when losses of oil or gas associated with common events and operations will be deemed “avoidable” or “unavoidable,” does not depend on, and may operate effectively in the absence of, revised § 3179.201, which determines when the flaring of associated gas from oil wells will be royalty-bearing.

B. Section-by-Section Discussion

1. 2016 rule Requirements Rescinded

As was proposed, the BLM rescinds the following provisions of the 2016 rule in this final rule:

43 CFR 3162.3-1(j) - Drilling applications and plans.

In the 2016 rule, the BLM added a paragraph (j) to 43 CFR 3162.3-1, which required that, when submitting an Application for Permit to Drill (APD) for an oil well, an operator must also submit a waste-minimization plan. Submission of the plan was required for approval of the APD, but the plan was not itself part of the APD, and the terms of the plan were not enforceable against the operator. The purpose of the waste-minimization plan was for the operator to set forth a strategy for how the operator would comply with the requirements of 43 CFR subpart 3179 regarding the control of waste from venting and flaring from oil wells.

The waste-minimization plan was required to include information regarding: The anticipated completion date(s) of the proposed oil well(s); a description of anticipated production from the well(s); certification that the operator has provided one or more midstream processing companies with information about the operator’s production plans,

including the anticipated completion dates and gas production rates of the proposed well or wells; and identification of a gas pipeline to which the operator plans to connect.

Additional information was required when an operator could not identify a gas pipeline with sufficient capacity to accommodate the anticipated production from the proposed well, including: A gas pipeline system location map showing the proposed well(s); the name and location of the gas processing plant(s) closest to the proposed well(s); all existing gas trunklines within 20 miles of the well, and proposed routes for connection to a trunkline; the total volume of produced gas, and percentage of total produced gas, that the operator is currently venting or flaring from wells in the same field and any wells within a 20-mile radius of that field; and a detailed evaluation, including estimates of costs and returns, of potential on-site capture approaches.

The BLM estimates that the administrative burden of the waste-minimization plan requirements would be roughly $5 million per year for industry and $800,000 per year for the BLM (RIA at Section 7.1).

This final rule rescinds the waste minimization plan requirement of § 3162.3-1(j). The BLM believes that the waste minimization plan requirement imposed an unnecessary administrative burden on both operators and the BLM. The purpose of the waste-minimization-plan requirement was to guide an operator’s behavior by forcing it to collect and consider information pertaining to gas capture. The BLM believes that there will be sufficient information-based safeguards against undue waste even in the absence of the waste-minimization-plan requirement for the following reasons. First, the BLM has found that comparable gas-capture-plan requirements in North Dakota and New Mexico will ensure that operators in those States take account of the availability of

capture infrastructure. In New Mexico, the operator must submit a gas-capture plan when seeking permission to drill a well. In North Dakota, the operator must submit a gas-capture plan when seeking permission to drill a well if the operator has not been in compliance with the State's gas-capture requirements during any of the most recent 3 months. The BLM notes that more than half of the flaring of Federal and Indian gas occurs in the states of North Dakota and New Mexico. Second, State regulations in Utah, Wyoming, and Montana require operators to submit production information similar to that required under § 3162.3-1(j)(2) when operators seek approval for long-term flaring of associated gas. In these States, both operators and State regulators will be able to consider the potential for capture before long-term flaring of associated gas can be approved. Finally, under § 3179.201(c), applicable in the absence of State or tribal regulation for the flaring of associated gas, an operator is required to submit one of the following before it could receive approval for royalty-free flaring of associated gas under final § 3179.201(c): (1) A report supported by engineering, geologic, and economic data which demonstrates to the BLM's satisfaction that the expenditures necessary to market or use the gas are not economically justified; or (2) An action plan that will eliminate the flaring within a time period approved by the BLM. All of these requirements will help to fulfill the purpose of § 3162.3-1(j), which is to ensure that operators do not waste gas without giving due consideration to the possibility of marketing or using the gas.

In addition, the extensive amount of information that an operator must include in the waste-minimization plan makes compliance with the requirement cumbersome for operators. Operators have also expressed concern that the waste-minimization-plan requirement will slow down APD processing as BLM personnel take time to determine

whether the waste-minimization plan submitted by an operator is “complete and adequate,” and whether the operator has provided all required pipeline information to the full extent that the operator can obtain it.

Some commenters expressed support for the rescission of § 3162.3-1(j), arguing that the BLM’s waste-minimization-plan requirement was redundant with State requirements and reflected an inappropriate “one size fits all” approach to basin-specific infrastructure problems. These commenters further argued that the BLM had erroneously assumed that, unless operators are forced to gather information pertaining to gas capture infrastructure, they will not do so or will not pursue opportunities to capture and market associated gas when economically justified. Some commenters argued that the BLM has not justified the rescission of the waste-minimization-plan requirement because: New Mexico has not been enforcing its comparable requirement; the process for seeking approval for flaring in Utah, Wyoming, and Montana is not an adequate substitute since the information is submitted after the well has been approved and drilled; and, the BLM can allocate more resources to APD processing to ensure that the waste-minimization-plan requirement does not slow down APD processing. First, the BLM is aware of no evidence that New Mexico is not implementing its gas capture plan requirement. Second, the BLM does not agree that the timing of the applications to flare—whether under Utah, Wyoming, or Montana State regulations or § 3179.201(c)—precludes operators and regulators from using the information to make prudent determinations about whether flaring or capture is warranted. The fact that a well has already been drilled does not preclude State regulators from denying approval to flare where production and infrastructure information indicates that capture is warranted. Finally, the BLM does not

see the need to allocate additional BLM resources to accommodate a requirement that is duplicative of State requirements in the two States with the highest rates of flaring and provides limited additional benefit (if any) in other States where flaring is less prevalent and/or State regulations require similar information to be submitted to regulators in order to obtain permission to flare.

In light of the foregoing, the BLM concludes that there is limited (if any) benefit to the waste minimization plan requirement of § 3162.3-1(j) and is therefore rescinding it in its entirety.

The BLM has summarized and responded to the comments received on the rescission of § 3162.3-1(j) in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.7 – Gas-capture requirement.

In the 2016 rule, the BLM sought to constrain the routine flaring of associated gas through the imposition of a "capture percentage" requirement, requiring operators to capture a certain percentage of the gas they produce, after allowing for a certain volume of flaring per well. The capture percentage requirement would have become more stringent over a period of years, beginning with an 85 percent capture requirement (5,400 Mcf per well flaring allowable) in January 2018, and eventually reaching a 98 percent capture requirement (750 Mcf per well flaring allowable) in January 2026. An operator could choose to comply with the capture targets on each of the operator's leases, units or communitized areas, or on a county-wide or state-wide basis.

As proposed, this final rule rescinds the 2016 rule's capture percentage requirements for a number of reasons. First, the BLM estimates that this requirement, over 10 years from 2019-2028, would impose costs of $556 million to $1.10 billion and generate cost savings from product recovery of $381 to $507 million (RIA at Section 4.4). That is, the BLM's estimates indicate that the 2016 rule's capture-percentage requirements would have imposed costs that exceeded the value of the gas that they were expected to conserve. Because the capture-percentage requirements are expected to impose net costs, the BLM believes that it is appropriate to rescind them and replace them with a different approach to regulating the flaring of associated gas.

In addition, the BLM has identified a number of practical problems with the 2016 rule's capture percentage requirements. In the early years, when capture percentages would not be as high and allowable flaring would be high, the 2016 rule would have allowed for large amounts of royalty-free flaring. In the later years, the BLM believes that the 2016 rule would have introduced complexities that would have undermined its effectiveness. Because of the common use of horizontal drilling through multiple leaseholds of different ownership, the 2016 rule's coordination requirements in previous § 3179.12 (providing for coordination with States and tribes when any requirement would adversely impact production from non-Federal and non-Indian interests) created a high degree of uncertainty over how the capture requirements would have been implemented and what their impact would have been. Even if the capture percentage requirements were to be implemented and effective as written, the BLM is concerned that the prescriptive nature of the approach would have allowed for unnecessary flaring in some cases while prohibiting necessary flaring in others. For example, even if an operator

could feasibly capture all of the gas it produces from a Federal well, the operator could still flare a certain amount of gas without violating previous § 3179.7's capture-percentage requirements. Thus, in situations where the operator faced transmission or processing-plant capacity limitations (i.e., where a pipeline or processing plant does not have the capacity to take all of the gas that is being supplied to it), previous § 3179.7 would have allowed the operator to flare gas from a Federal well in order to produce more gas from a nearby non-Federal well for which there are tighter regulatory or contractual constraints on flaring.

Furthermore, the capture-percentage requirement afforded less flexibility for smaller operators with fewer operating wells than it would have for larger operators with a greater number of operating wells. A small operator with only a few wells in an area with inadequate gas-capture infrastructure would have likely been faced with curtailing production or violating § 3179.7's prescriptive limits. On the other hand, a larger operator with many wells would have had greater flexibility to average the flaring allowable over its portfolio and avoid curtailing production or other production constraints.

In place of the 2016 rule's capture-percentage requirements, the final rule, as was proposed, addresses the routine flaring of associated gas by deferring to State or tribal regulations where possible and codifying the familiar NTL-4A standard for royalty-free flaring as a backstop where no applicable State or tribal regulation exists. The final rule's approach to the routine flaring of associated gas is explained more fully below (see the discussion of § 3179.201).

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of § 3179.7 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.). Many of the comments received about this section expressed dissatisfaction with BLM giving deference to state regulations in § 3179.201. Those comments are addressed in the discussion of final § 3179.201.

43 CFR 3179.8 - Alternative capture requirement.

Previous § 3179.8 allowed operators of leases issued before January 17, 2017, to request a lower capture percentage requirement than would otherwise be imposed under § 3179.7. In order to obtain this lower capture requirement, an operator would have had to demonstrate that the applicable capture percentage under § 3179.7 would "impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease." Because the BLM is rescinding the capture percentage requirements of previous § 3179.7, the BLM is also rescinding the mechanism for obtaining a lower capture requirement, as was proposed. Because § 3179.7 is now rescinded, there is no need for previous § 3179.8.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of §§ 3179.8 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.11 - Other waste prevention measures.

Previous § 3179.11(a) stated that the BLM may exercise its existing authority under applicable laws and regulations, as well as under the terms of applicable permits, orders, leases, and unitization or communitization agreements, to limit production from a new well that is expected to force other wells off of a common pipeline. Previous § 3179.11(b) stated that the BLM could similarly exercise existing authority to delay action on an APD or impose conditions of approval on an APD. Previous § 3179.11 was not an independent source of authority or obligation on the part of the BLM. Rather, previous § 3179.11 was intended to clarify how the BLM could exercise existing authorities in addressing the waste of gas. However, the BLM understands that previous § 3179.11 could easily be misread to indicate that the BLM has plenary authority to curtail production or delay or condition APDs regardless of the circumstances. Because previous § 3179.11 is unnecessary and is susceptible to misinterpretation, the BLM is rescinding it, as proposed.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of §§ 3179.11 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.12 - Coordination with State regulatory authority.

Previous § 3179.12 stated that, to the extent an action to enforce 43 CFR subpart 3179 may adversely affect production of oil or gas from non-Federal and non-Indian mineral interests, the BLM will coordinate with the appropriate State regulatory

authority. The purpose of this provision was to ensure that due regard was given to the States' interests in regulating the production of non-Federal and non-Indian oil and gas. As was proposed, in this final rule the BLM has rescinded previous § 3179.12 because, as explained more fully below, the BLM revised subpart 3179 in a manner that defers to State and tribal requirements with respect to the routine flaring of associated gas. In light of this new approach, the BLM believes that there is much less concern that subpart 3179 could be applied in ways that State regulatory agencies find to be objectionable or in ways that would adversely affect oil or gas production from non-Federal and non-Indian mineral interests. The BLM continues to recognize the value of coordinating with State regulatory agencies, but no longer considers it necessary to include a coordination requirement in subpart 3179.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of §§ 3179.12 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.101 - Well drilling.

Previous § 3179.101(a) required gas reaching the surface as a normal part of drilling operations to be used or disposed of in one of four ways: (1) Captured and sold; (2) Directed to a flare pit or flare stack; (3) Used in the operations on the lease, unit, or communitized area; or (4) Injected. Previous § 3179.101(a) also specified that gas may not be vented, except under the circumstances specified in previous § 3179.6(b) or when it was technically infeasible to use or dispose of the gas in one of the ways specified

above. Previous § 3179.101(b) stated that gas lost as a result of a loss of well control would be classified as avoidably lost if the BLM determined that the loss of well control was due to operator negligence.

As was proposed, the BLM is rescinding previous § 3179.101 because it would be duplicative under final subpart 3179. In essence, § 3179.101(a) required an operator to flare gas lost during well drilling rather than vent it (unless technically infeasible). This same requirement is contained in final § 3179.6(b). Previous § 3179.101(b) stated that where gas was lost during a loss of well control, the lost gas would be considered "avoidably lost" if the BLM determined that the loss of well control was due to operator negligence. This principle is contained in final § 3179.4(b), which requires an absence of operator negligence in order for lost gas to be considered "unavoidably lost."

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of § 3179.101 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov. (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.). The comments that opposed the rescission of this section asserted that there would be no state or EPA backstop if BLM rescinds the section. In its response to these comments, BLM explains that the essential requirements of former § 3179.101 are retained in the revised rule.

43 CFR 3179.102 - Well completion and related operations.

Previous § 3179.102 addressed gas that reached the surface during well-completion, post-completion, and fluid-recovery operations after a well has been

hydraulically fractured or refractured. It required the gas to be disposed of in one of four ways: (1) Captured and sold; (2) Directed to a flare pit or stack, subject to a volumetric limitation in § 3179.103; (3) Used in the lease operations; or (4) Injected. Previous § 3179.102 specified that gas could not be vented, except under the narrow circumstances specified in previous § 3179.6(b) or when it was technically infeasible to use or dispose of the gas in one of the four ways specified above. Previous § 3179.102(b) provided that an operator would be deemed to be in compliance with its gas capture and disposition requirements if the operator was in compliance with the requirements for control of gas from well completions established under 40 CFR part 60, subparts OOOO or OOOOa, or if the well was not a "well affected facility" under those regulations. Previous § 3179.102(c) and (d) allowed the BLM to exempt an operator from the requirements of previous § 3179.102 where the operator demonstrated that compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

As was proposed, this final rule rescinds previous § 3179.102 in its entirety. The EPA finalized regulations in 40 CFR part 60, subpart OOOO and OOOOa, that are applicable to all of the well completions covered by previous § 3179.102. See 81 FR 35824 (June 3, 2016); 81 FR 83055–56. In light of the complete overlap with EPA regulations, and the fact that compliance with these regulations satisfies an operator's obligations under previous § 3179.102, the BLM has concluded that previous § 3179.102 is duplicative and unnecessary. In the 2016 rule, the BLM recognized the duplicative nature of § 3179.102, but sought to establish a "backstop" in the "unlikely event" that the analogous EPA regulations ceased to be in effect. See 81 FR 83056. The BLM no

longer believes that it is appropriate to insert duplicative regulations into the Code of Federal Regulations as insurance against unlikely events. In addition, the BLM questions the appropriateness of issuing regulations that serve as a backstop to the regulations of other Federal agencies, especially when those agencies have promulgated their regulations under different authorities.

The BLM notes that, under revised § 3179.4(b)(2), the BLM reserves the right to limit royalty-free flaring during well-completion operations based on the operator's negligence or failure to take reasonable precautions to prevent the loss. Furthermore, the implicit requirement of previous § 3179.102 that gas that reaches the surface during well-completion operations be disposed of by some means other than venting is maintained in the general venting prohibition of final § 3179.6.

In light of the foregoing, the BLM is rescinding previous § 3179.102 in its entirety.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of §§ 3179.102 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.201 - Equipment requirements for pneumatic controllers.

Previous § 3179.201 addressed pneumatic controllers that use natural gas produced from a Federal or Indian lease, or from a unit or communitized area that includes a Federal or Indian lease. Previous § 3179.201 applied to such controllers if the controllers: (1) Had a continuous bleed rate greater than 6 standard cubic feet per hour

(scf/hour) ("high-bleed" controllers); and (2) Were not covered by EPA regulations that prohibit the new use of high-bleed pneumatic controllers (40 CFR part 60, subparts OOOO or OOOOa), but would have been subject to those regulations if the controllers were new, modified, or reconstructed. Previous § 3179.201(b) required the applicable pneumatic controllers to be replaced with controllers (including, but not limited to, continuous or intermittent pneumatic controllers) having a bleed rate of no more than 6 scf/hour, subject to certain exceptions. Previous § 3179.201(d) (as amended by the 2017 Suspension Rule) required that this replacement occur no later than January 17, 2019, or within 3 years from the effective date of the 2016 rule if the well or facility served by the controller had an estimated remaining productive life of 3 years or less. Previous § 3179.201(b)(4) and (c) allowed the BLM to exempt an operator from the requirements of previous § 3179.201 where the operator demonstrated that compliance would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

The BLM estimates that this requirement, over 10 years from 2019-2028, would have imposed costs of about $12 million to $13 million and would have generated cost savings from product recovery of $20 million to $26 million (RIA at Section 4.4). As was proposed, this final rule rescinds previous § 3179.201 in its entirety. Low-bleed continuous pneumatic controllers are expected to generate revenue for operators when employed at sites from which gas is captured and sold and when the sale price of gas is generally higher than it is now. Thus, the BLM expects many operators to adopt low-bleed pneumatic controllers even in the absence of previous § 3179.201's requirements. This belief is supported by the fact that low-bleed continuous pneumatic controllers are

already very common, representing about 89 percent of the continuous bleed pneumatic controllers in the petroleum and natural gas production sectors.[33] Because low-bleed pneumatic controllers are often cost-effective and are already very common, the BLM does not believe that it is necessary to maintain previous § 3179.201 in its regulations, even though it was expected to result in overall cost savings.

The BLM notes that the EPA has regulations in 40 CFR part 60, subparts OOOO and OOOOa that require new, modified, or reconstructed continuous bleed controllers to be low-bleed. As new facilities on Federal and Indian leases come online and more of the existing high-bleed continuous controllers are replaced, these EPA regulations will require the installation of low-bleed continuous controllers. The BLM understands the typical lifespan of a pneumatic controller to be 10 to 15 years. Finally, as discussed above, the BLM recognizes that the oil and gas exploration and production industry continues to pursue reductions in methane emissions on a voluntary basis, and the BLM expects these efforts to result in a reduction in the number of high-bleed pneumatic devices employed by the industry.

In addition to the explanation provided here, which addresses most of the issues raised in the comments that BLM received about the rescission of this section, the BLM has summarized and responded to the comments received about the rescission of § 3179.201 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-

[33] Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015, Annex 3 (published April 2017). Data are available in Table 3.5-5 and Table 3.6-7.

AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.202 - Requirements for pneumatic diaphragm pumps.

Previous § 3179.202 established requirements for operators with pneumatic diaphragm pumps that use natural gas produced from a Federal or Indian lease, or from a unit or communitized area that included a Federal or Indian lease. It applied to such pumps if they were not covered under EPA regulations at 40 CFR part 60, subpart OOOOa, but would be subject to that subpart if they were a new, modified, or reconstructed source. For covered pneumatic pumps, previous § 3179.202 required that the operator either replace the pump with a zero-emissions pump or route the pump exhaust to processing equipment for capture and sale. Alternatively, an operator had the option of routing the exhaust to a flare or low-pressure combustion device if the operator made a determination (and notifies the BLM through a Sundry Notices and Reports on Wells, Form 3160-5) that replacing the pneumatic diaphragm pump with a zero-emissions pump or capturing the pump exhaust was not viable because: (1) A pneumatic pump was necessary to perform the function required; and (2) Capturing the exhaust was technically infeasible or unduly costly. If an operator made this determination and had no flare or low-pressure combustor on-site, or routing to such a device would have been technically infeasible, the operator was not required to route the exhaust to a flare or low-pressure combustion device. Under previous § 3179.202(h), an operator was required to replace its covered pneumatic diaphragm pump or route the exhaust gas to capture or flare beginning no later than January 17, 2018. Previous § 3179.202(f) and (g) would have allowed the BLM to exempt an operator from the requirements of previous §

3179.202 where the operator demonstrated that compliance would have caused the operator to cease production and abandon significant recoverable oil reserves under the lease.

The BLM estimates that the costs of compliance with previous § 3179.202 would have outweighed the value of its conservation effects. Specifically, the BLM estimates that § 3179.202, over 10 years from 2019-2028, would have imposed costs of about $29 million to $30 million, while only generating cost savings from product recovery of $15 million to $19 million (RIA at Section 4.4). Because previous § 3179.202 imposed compliance costs greater than the value of the resources it was expected to conserve, the BLM does not consider it to be an appropriate "waste prevention" requirement, and is rescinding it in its entirety, as was proposed.

The BLM notes that, as discussed above, industry is making ongoing efforts to retire old leak-prone equipment, including pneumatic pumps, on a voluntary basis. Furthermore, analogous EPA regulations in 40 CFR part 60, subpart OOOOa, will reduce the loss of gas from pneumatic diaphragm pumps on Federal and Indian leases as more and more of them are covered by the EPA regulations over time. These reasons further support rescission of previous § 3179.202.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of § 3179.202 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.203 - Storage vessels.

Previous § 3179.203 applied to crude oil, condensate, intermediate hydrocarbon liquid, or produced-water storage vessels that contained production from a Federal or Indian lease, or from a unit or communitized area that included a Federal or Indian lease, and that were not subject to 40 CFR part 60, subparts OOOO or OOOOa, but would be if they were new, modified, or reconstructed sources. If such storage vessels had the potential for volatile organic compound (VOC) emissions equal to or greater than 6 tons per year (tpy), previous § 3179.203 required operators to route all gas vapor from the vessels to a sales line. Alternatively, the operator could have routed the vapor to a combustion device if it determined that routing the vapor to a sales line was technically infeasible or unduly costly. The operator could have also submitted a Sundry Notice to the BLM that demonstrated that compliance with the above options would cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

As proposed, the BLM is rescinding previous § 3179.203 in its entirety. The BLM finds that the costs of compliance with previous § 3179.203 would have outweighed the value of its conservation effects. Specifically, the BLM estimates that previous § 3179.203, over 10 years from 2019-2028, would have imposed costs of about $51 million to $56 million while only generating cost savings from product recovery of about $1 million (RIA at Section 4.4). The BLM has always believed that previous § 3179.203 would have a limited reach, due to the 6 tpy emissions threshold and the carve-out for storage vessels covered by EPA regulations. The BLM estimated in the RIA for the 2016 rule that § 3179.203 would impact fewer than 300 facilities on Federal and Indian lands (2016 RIA at 69). Because previous § 3179.203 imposed compliance costs

well in excess of the value of the resources it was expected to conserve, the BLM does not consider it to be an appropriate "waste prevention" requirement, and is rescinding it in its entirety.

Finally, the BLM notes that, even with § 3179.203 rescinded, the BLM retains the authority to impose royalties on vapor losses from storage vessels under final § 3179.4(b)(2)(vii) when the BLM determines that recovery of the vapors is warranted.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of § 3179.203 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.301 through 3179.305 - Leak detection and repair.

Previous §§ 3179.301 through 3179.305 established leak detection, repair, and reporting requirements for: (1) Sites and equipment used to produce, process, treat, store, or measure natural gas from or allocable to a Federal or Indian lease, unit, or communitization agreement; and (2) Sites and equipment used to store, measure, or dispose of produced water on a Federal or Indian lease. Previous § 3179.302 prescribed the instruments and methods that may have been used for leak detection. Previous § 3179.303 prescribed the frequency for inspections and previous § 3179.304 prescribed the time frames for repairing leaks found during inspections. Finally, previous § 3179.305 required operators to maintain records of their LDAR activities and submit an annual report to the BLM. Pursuant to previous § 3179.301(f), operators were required to begin to comply with the LDAR requirements of previous §§ 3179.301 through 3179.305

before: (1) January 17, 2018, for all existing sites; (2) 60 days after beginning production for sites that begin production after January 17, 2017; and (3) 60 days after a site that was out of service was brought back into service and re-pressurized.

As proposed, the BLM is rescinding previous §§ 3179.301 to 3179.305 in their entirety. The BLM finds that the costs of compliance with §§ 3179.301 to 3179.305 outweigh the value of their conservation effects. The BLM estimates that these requirements, over 10 years from 2019-2028, would have imposed costs of about $550 million to $688 million while only generating cost savings from product recovery of about $101 million to $128 million (RIA at Section 4.4). In addition, the BLM estimates that the administrative burdens associated with the LDAR requirements, at roughly $5 million, would have represented the bulk of the administrative burdens of the 2016 rule. Because the 2016 rule's LDAR requirements would have imposed compliance costs well in excess of the value of the resources they were expected to conserve, the BLM does not consider them to be appropriate "waste prevention" requirements, and is rescinding them in their entirety.

The BLM has identified additional problems with the 2016 rule's LDAR requirements—beyond their unjustified costs—that further support rescission. First, the LDAR requirements inappropriately applied to all wellsites equally. Wellsites that are not connected to deliver gas to market would not achieve any waste reduction because sales from the recovered gas would not be realized. Second, the LDAR requirements posed an unnecessary burden to operators of marginal wells, particularly marginal oil wells. The BLM does not estimate that the potential fugitive gas losses from marginal oil wells would be substantial enough to warrant the costs of maintaining an LDAR program

with semi-annual inspection frequencies. As noted previously, the BLM estimates that over 73 percent of oil wells on the public lands are marginal.

Some commenters argued that, rather than rescinding the LDAR requirements in their entirety, the BLM should have considered alternative LDAR requirements that would have been less burdensome to operators. The BLM appreciates the commenters' concern with examining alternative approaches to LDAR. The BLM considered a reasonable range of LDAR alternatives and determined that the rescission of the LDAR requirements of the 2016 final rule is appropriate. This determination was based on the following information. In the RIA for the 2016 rule, the BLM examined the impacts of a range of alternative approaches for LDAR. See 2016 RIA at 91-93. Specifically the RIA examined the five following LDAR alternatives: (1) Semi-annual inspections (adopted in the 2016 rule); (2) Quarterly inspections; (3) Semi-annual inspections, but annual inspections for oil wells with <300 gas/oil ratio (GOR); (4) Semi-annual inspections, exempting oil wells with <300 GOR; and (5) Annual inspections. Note that the last three alternatives would have imposed fewer compliance costs than the alternative adopted in the 2016 rule. However, for all of the alternatives examined, compliance costs greatly outweighed cost savings (i.e., the value of the gas conserved). The annual inspections alternative was the least burdensome in terms of compliance costs. However, the 2016 RIA estimated that this alternative would impose costs of about $48 million per year while generating only $8 million to $14 million in annual cost savings. Finally, even when including estimates of benefits associated with foregone emissions (using the domestic social cost of methane), the BLM found net costs for all of the alternatives

analyzed in the 2016 RIA. In light of this information, the BLM continues to assess that the rescission of the LDAR requirements of the 2016 final rule is appropriate.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on the rescission of §§ 3179.301-305 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.401 - State or tribal requests for variances from the requirements of this subpart

Previous § 3179.401 would have allowed a State or tribe to request a variance from any provisions of subpart 3179 by identifying a State, local, or tribal regulation to be applied in place of those provisions and demonstrating that such State, local, or tribal regulation would perform at least equally well as those provisions in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas.

As was proposed, the BLM is rescinding previous § 3179.401 because it believes that the variance process established by this section was too restrictive and is no longer necessary in light of the BLM's action to re-institute NTL-4A standards and to defer to State and tribal regulations for the flaring of associated gas, as explained in the discussion of final § 3179.201. Notably, in this final rule, the BLM has chosen to include a new § 3179.401, described below, which will allow for additional deference to tribal regulations. We discuss tribal comments received on this section below.

2. **Final Subpart 3179**

With this final rule, the BLM is revising subpart 3179, as follows:

43 CFR 3179.1 Purpose.

Section 3179.1 states that the purpose of 43 CFR subpart 3179 is to implement and carry out the purposes of statutes relating to prevention of waste from Federal and Indian leases, the conservation of surface resources, and management of the public lands for multiple use and sustained yield. The BLM is not revising existing § 3179.1 as a part of this rulemaking. Section 3179.1 is presented here for context.

43 CFR 3179.2 Scope.

This section specifies which leases, agreements, tracts, and facilities are covered by this subpart. The section also states that subpart 3179 applies to Indian Mineral Development Act (IMDA) agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement, and to agreements for the development of tribal energy resources under a Tribal Energy Resource Agreement entered into with the Secretary of the Interior, unless specifically excluded in the agreement. Existing § 3179.2 remains largely unchanged. However, the BLM is revising paragraph (a)(5) by using the more-inclusive words "well facilities" instead of the words "wells, tanks, compressors, and other equipment" to describe the onshore equipment that is subject to this final rule. The purpose of the phrase "wells, tanks, compressors, and other equipment" was to specify components subject to LDAR requirements which, as described above, the BLM is rescinding.

43 CFR 3179.3 Definitions and acronyms.

As was proposed, this section keeps, in their entirety, four of the 18 definitions that appear in previous § 3179.3: "Automatic ignition system," "gas-to-oil ratio,"

"liquids unloading," and "lost oil or lost gas." The definition for "capture" is retained in this final rule as it appeared in previous § 3179.3, except, as proposed, the word "reinjection" has been changed to "injection" to be consistent with references to conservation by injection (as opposed to reinjection) elsewhere in subpart 3179.

A definition for "gas well" is also maintained in this final rule, however the second and third sentences in the existing definition are removed, as was proposed. The second-to-last sentence in the previous definition of "gas well" is removed because, although a well's designation as a "gas" well or "oil" well is appropriately determined by the relative energy values of the well's products, the 6,000 scf/bbl standard in previous § 3179.3 is not a commonly used standard. The last sentence in the existing definition of "gas well," which states generally that an oil well will not be reclassified as a gas well when its gas-to-oil ratio (GOR) exceeds the 6,000 scf/bbl threshold, is removed and replaced with a simpler qualifier making clear that a well's status as a "gas well" is "determined at the time of completion."

As was proposed, a new definition for "oil well" is added in this final rule that defines an "oil well" as a "well for which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced, as determined at the time of completion." The addition of a definition of "oil well" should help to make clear when final § 3179.201's requirements for "oil-well gas" apply.

In the proposed rule, the BLM proposed to add a definition of "waste of oil or gas" that would define waste, for the purposes of subpart 3179, to mean any act or failure to act by the operator that is not sanctioned by the authorized officer as necessary for proper development and production, where compliance costs are not greater than the

monetary value of the resources they are expected to conserve, and which results in: (1) A reduction in the quantity or quality of oil and gas ultimately producible from a reservoir under prudent and proper operations; or (2) Avoidable surface loss of oil or gas. This proposed definition incorporated the definition of “waste of oil or gas” from the BLM’s operating regulations at 43 CFR 3160.0-5, but added an economic limitation: Waste does not occur where the cost of conserving the oil or gas exceeds the monetary value of that oil or gas. The BLM requested public comment on this proposed definition. Some commenters expressed support for the economic standard contained in the definition and argued that it would be consistent with the MLA’s concept of “waste,” as well as past BLM practice. Other commenters argued that “waste of oil or gas” expressed the same concept as “avoidably lost” production, and that the new definition of “waste of oil or gas” was therefore superfluous and could create confusion to the extent that it could be read as inconsistent with the definition of “avoidably lost” production in § 3179.4(a). Still other commenters noted that the practical application of the definition of “waste of oil or gas” would be difficult because the definition did not contain a time horizon over which the operator should evaluate its compliance costs and the value of the resources that compliance would be expected to conserve. The BLM has chosen to retain the proposed definition of “waste of oil or gas” in the final rule. This definition codifies the BLM’s policy determination that it is not appropriate for “waste prevention” regulations to impose compliance costs greater than the value of the resources they are expected to conserve. Because the term “waste of oil or gas” is not used in subpart 3179 (outside of the definitions section), the BLM does not expect any conflict between this definition and the provisions of § 3179.4, which identify “avoidably lost” oil or gas.

However, if a conflict ever arises, the BLM will view § 3179.4 as controlling on the question of what constitutes a royalty-bearing "avoidable" loss of oil or gas. Although the definition does not contain a specific time horizon for comparing the value of resources conserved to the cost of conservation, the BLM notes that, to the extent a technical application of this definition would ever be required under these regulations (which is unlikely given the fact that the phrase is not used in subpart 3179 outside of the definitions section), there is no reason to believe that the BLM would not employ a reasonable time frame in assessing costs and benefits.

As was proposed, this section removes 12 definitions from the previous regulations because they are no longer needed: "Accessible component," "capture infrastructure," "compressor station," "continuous bleed," "development oil well," "high pressure flare," "leak," "leak component," "liquid hydrocarbon," "pneumatic controller," "storage vessel," and "volatile organic compounds (VOC)." These definitions pertain to requirements in previous subpart 3179 that the BLM is rescinding.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.3 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.4 Determining when the loss of oil or gas is avoidable or unavoidable.

Final § 3179.4 describes the circumstances under which lost oil or gas is classified as "avoidably lost" or "unavoidably lost." None of the language in this section of the final rule has changed from the language that BLM proposed. Under final § 3179.5,

royalty is due on all avoidably lost oil or gas, while royalty is not due on unavoidably lost oil or gas. Final § 3179.4 includes concepts from both previous § 3179.4 and NTL-4A, Sections II. and III.

Final paragraph (a) defines “avoidably lost” production and mirrors the “avoidably lost” definition in NTL-4A Section II.A. Final paragraph (a) defines avoidably lost gas as gas that is vented or flared without BLM approval, and produced oil or gas that is lost due to operator negligence, the operator’s failure to take all reasonable measures to prevent or control the loss, or the operator’s failure to comply fully with applicable lease terms and regulations, appropriate provisions of the approved operating plan, or prior written BLM orders. This paragraph replaces the “avoidably lost” definition that appears in the last paragraph of previous § 3179.4, which primarily defined “avoidably lost” oil or gas as lost oil gas that is not “unavoidably lost” and also expressly included “excess flared gas” as defined in previous § 3179.7, which the BLM is rescinding.

Final paragraph (b) defines “unavoidably lost” production. Final paragraph (b)(1) follows language from Section II.C(2) of NTL-4A. It states that oil or gas that is lost due to line failures, equipment malfunctions, blowouts, fires, or other similar circumstances is considered to be unavoidably lost production, unless the BLM determines that the loss was avoidable under § 3179.4(a)(2)—i.e., the loss resulted from operator negligence, the failure to take all reasonable measures to prevent or control the loss, or the failure of the operator to comply fully with applicable lease terms and regulations, appropriate provisions of the approved operating plan, or prior written orders of the BLM.

Final paragraph (b)(2) is substantially similar to the definition of "unavoidably lost" oil or gas that appears in previous § 3179.4(a). This paragraph improves upon NTL-4A by providing clarity to operators and the BLM about which losses of oil or gas should be considered "unavoidably lost." Paragraph (b)(2) introduces a list of operations or sources from which lost oil or gas is considered "unavoidably lost," so long as the operator has not been negligent, has taken all reasonable measures to prevent or control the loss, and has complied fully with applicable laws, lease terms, regulations, provisions of a previously approved operating plan, or other written orders of the BLM, as provided in § 3179.4(a)(2).

Except for cross references, final § 3179.4(b)(2)(i) through (vi) are the same as paragraphs (a)(1)(i) through (vi) in previous § 3179.4. These paragraphs list the following operations or sources from which lost oil or gas would be considered "unavoidably lost": Well drilling; well completion and related operations; initial production tests; subsequent well tests; exploratory coalbed methane well dewatering; and emergencies.

This final rule removes normal operating losses from pneumatic controllers and pumps (previous § 3179.4(a)(1)(vii)) from the list of unavoidable losses because the use of gas in pneumatic controllers and pumps is already royalty free under previous § 3178.4(a)(3).

Final paragraph (b)(2)(vii) is similar to previous § 3179.4(a)(1)(viii), but has been rephrased to reflect the NTL-4A provisions pertaining to storage-tank losses (NTL-4A Section II.C(1)). Under final § 3179.4(b)(2)(vii), normal gas vapor losses from a storage tank or other low-pressure production vessel are unavoidably lost, unless the BLM

determines that recovery of the vapors is warranted. Changing the phrase "operating losses" (as used in previous § 3179.4(a)(1)(viii)) to "gas-vapor losses" makes clear that this provision applies to low-pressure gas losses.

Final § 3179.4(b)(2)(viii) is the same as previous § 3179.4(a)(1)(ix). It states that well venting in the course of downhole well maintenance and/or liquids unloading performed in compliance with § 3179.104 is an operation from which lost gas is considered "unavoidably lost."

The final rule does not retain previous § 3179.4(a)(1)(x), which classified leaks as unavoidable losses when the operator has complied with the LDAR requirements in previous §§ 3179.301 through 3179.305. The BLM is rescinding these LDAR requirements and so there is no need to reference these requirements as a limitation on losses through leaks.

Final § 3179.4(b)(2)(ix) is the same as previous § 3179.4(a)(1)(xi), identifying facility and pipeline maintenance, such as when an operator must blow-down and depressurize equipment to perform maintenance or repairs, as an operation from which lost oil or gas would be considered "unavoidably lost," so long as the operator has not been negligent and has complied with all appropriate requirements.

The final rule does not include previous § 3179.4(a)(1)(xii). This paragraph listed the flaring of gas from which at least 50 percent of natural gas liquids have been removed and captured for market as an unavoidable loss. This provision was included in the 2016 rule as part of the BLM's effort to adopt a gas-capture percentage scheme similar to that of North Dakota. The BLM is removing this provision because it is rescinding the gas-capture percentage requirements contained in the 2016 rule.

The final rule does not include previous § 3179.4(a)(2). Previous § 3179.4(a)(2) provided that gas that is flared or vented from a well that is not connected to a gas pipeline is unavoidably lost, unless the BLM has determined otherwise. Previous § 3179.4(a)(2) was essentially a blanket approval for royalty-free flaring from wells not connected to a gas pipeline. Flaring from these wells, however, would no longer have been royalty free if the operator failed to meet the gas-capture requirements imposed by previous § 3179.7 and the flared gas thus became royalty-bearing "excess flared gas." Because the BLM is rescinding previous § 3179.7, maintaining previous § 3179.4(a)(2) would amount to sanctioning unrestricted flaring from wells not connected to gas pipelines. The routine flaring of oil-well gas from wells not connected to a gas pipeline is addressed by final § 3179.201, which is discussed in more detail below.

Final § 3179.4(b)(3) states that produced gas that is flared or vented with BLM authorization or approval is unavoidably lost. This provision mirrors final § 3179.4(a), which states that gas that is flared or vented without BLM authorization or approval is avoidably lost, and provides clarity to operators about royalty obligations with respect to authorized venting and flaring.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.4 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.5 When lost production is subject to royalty.

As proposed, the final rule does not change previous § 3179.5. This section continues to state that royalty is due on all avoidably lost oil or gas and that royalty is not due on any unavoidably lost oil or gas.

43 CFR 3179.6 Venting limitations.

The title of this section in the final rule has been changed from "venting prohibitions" to "venting limitations." As was proposed, the final rule retains most of the provisions in previous § 3179.6. The purpose of both sections is to prohibit flaring and venting from gas wells, with certain exceptions, and to require operators to flare, rather than vent, any uncaptured gas, whether from oil wells or gas wells, with certain exceptions.

Final § 3179.6(a) is the same as the previous § 3179.6(a), except the cross reference has been updated. It states that gas-well gas may not be flared or vented, except where it is unavoidably lost, pursuant to § 3179.4(b). This same restriction on the flaring of gas-well gas was included in NTL-4A.

Both previous and final § 3179.6(b) state that operators must flare, rather than vent, any gas that is not captured, with the exceptions listed in subsequent paragraphs. Although the text of NTL-4A did not contain a similar requirement that, in general, lost gas should be flared rather than vented, the implementing guidance for NTL-4A in the United States Geological Survey's (USGS) Conservation Division Manual did contain a similar preference for flaring over venting. The flaring of gas is generally preferable to the venting of gas due to safety concerns. Final § 3179.6(b) therefore represents an improvement on NTL-4A by making clear in the regulation, rather than in implementation guidance, that lost gas should be flared when possible.

The first three flaring exceptions in both the previous and final § 3179.6 are identical: Paragraph (b)(1) allows for venting when flaring is technically infeasible; paragraph (b)(2) allows for venting in the case of an emergency, when the loss of gas is uncontrollable, or when venting is necessary for safety; and, paragraph (b)(3) allows for venting when the gas is vented through normal operation of a natural-gas-activated pump or pneumatic controller.

The fourth flaring exception, listed in final § 3179.6(b)(4), allows gas vapors to be vented from a storage tank or other low-pressure production vessel, except when the BLM determines that gas-vapor recovery is warranted. Although this language is somewhat different than what appears in previous § 3179.6(b)(4), it has the same practical effect. As was proposed, it has been changed in this final rule to align the language with final § 3179.4(b)(vii) and to remove the cross-reference to the storage tank requirements in previous § 3179.203, which the BLM is rescinding.

The fifth exception, listed in final § 3179.6(b)(5), applies to gas that is vented during downhole well maintenance or liquids unloading activities. This is similar to previous § 3179.6(b)(5), except that the final rule, as was proposed, removes the cross reference to previous § 3179.204. Although the revision of subpart 3179 retains limitations on royalty-free losses of gas during well maintenance and liquids unloading in final § 3179.104, no cross-reference to those restrictions is necessary in this section, which simply addresses whether the gas may be vented or flared, not whether it is royalty-bearing.

The final rule removes the flaring exception listed in previous § 3179.6(b)(6), which applied to gas vented through a leak, provided that the operator had complied with

the LDAR requirements in previous §§ 3179.301 through 3179.305. The BLM is rescinding these LDAR requirements so there is no need to reference these requirements as a limitation on venting through leaks.

The sixth flaring exception, listed in final § 3179.6(b)(6), is identical to the exception listed in previous § 3179.6(b)(7). This exception allows gas venting that is necessary to allow non-routine facility and pipeline maintenance to be performed.

The seventh flaring exception, listed in final § 3179.6(b)(7), is identical to the exception listed in previous § 3179.6(b)(8). This exception allows venting when a release of gas is unavoidable under § 3179.4, and Federal, State, local, or tribal law, regulation, or enforceable permit terms prohibit flaring.

Final § 3179.6(c) is identical to previous § 3179.6(c). Both sections require all flares or combustion devices to be equipped with automatic ignition systems.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.6 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

Authorized Flaring and Venting of Gas

43 CFR 3179.101 Initial production testing.

As was proposed, final § 3179.101 establishes volume and duration standards which limit the amount of gas that may be flared royalty free during initial production testing. The gas is no longer royalty free after reaching either limit. Final § 3179.101 establishes a volume limit of 50 million cubic feet (MMcf) of gas that may be flared

royalty free during the initial production test of each completed interval in a well. Additionally, final § 3179.101 limits royalty-free initial production testing to a 30 day period, unless the BLM approves a longer period.

The 2016 rule also used volume and duration thresholds to limit royalty-free initial production testing. Previous § 3179.103 provided for up to 20 MMcf of gas to be flared royalty free during well drilling, well completion, and initial production testing operations combined. Under previous § 3179.103, upon receiving a Sundry Notice request from the operator, the BLM could have increased the volume of royalty-free flared gas up to an additional 30 MMcf. Under previous § 3179.103, similar to final § 3179.101, the BLM allowed royalty-free testing for a period of up to 30 days after the start of initial production testing. Under previous § 3179.103, the BLM could, upon request, extend the initial production testing period by up to an additional 60 days. Further, previous § 3179.103 provided additional time for dewatering and testing exploratory coalbed methane wells. Under previous § 3179.103, such wells had an initial royalty-free period of 90 days (rather than the 30 days applicable to all other well types), and the possibility of the BLM approving, upon request, up to two additional 90-day periods.

Under NTL-4A, gas lost during initial production testing was royalty free for a period not to exceed 30 days or the production of 50 MMcf of gas, whichever occurred first, unless a longer test period was authorized by the State and accepted by the BLM.

The volume and duration limits in final § 3179.101 are similar to those in previous § 3179.103 and NTL-4A. Both sections and NTL-4A allow 30 days from the start of the test, and all three allow for extensions of time. However, previous § 3179.103

limited an extension to no more than 60 days, whereas final § 3179.101 does not specify an extension limit. Final § 3179.101 allows for up to 50 MMcf of gas to be flared royalty free, with no express opportunity for an increase in the volume of royalty-free flaring during initial production testing. By comparison, previous § 3179.103 allowed for 20 MMcf to be flared royalty free, with the possibility of an additional 30 MMcf of gas flared with BLM approval, and no opportunity for additional royalty-free flaring beyond the cumulative 50 MMcf of gas.

Some commenters argued that the regulation should allow for operators to seek BLM approval for additional volumes of royalty-free flaring during initial production testing in the same way they can seek additional time for royalty-free flaring. Commenters also argued that the BLM should allow for additional time and volumes of royalty-free flaring when such longer periods or additional volumes of flaring are authorized by a State. The BLM does not agree with the comments and did not change § 3179.101 in response to them. Based on consultation with experienced BLM petroleum engineers and the fact that these limitations are consistent with longstanding standards in NTL-4A, the BLM believes the limitations in § 3179.101(a)(2) and (3) provide most operators sufficient time and volume for testing in a royalty-free status. Although an extension of the time period for initial production testing may sometimes be justified (as where the operator has failed to acquire adequate reservoir information), the volume threshold acts as a governor to ensure that the public and tribes are compensated for excessive losses of publicly or tribally owned gas during initial production testing. Beyond the 50 Mmcf threshold, the operator may continue initial production testing, but incurs a royalty obligation.

The provision for exploratory coalbed methane wells in previous § 3179.103 is the most notable difference between it and this final rule with regard to the initial production testing. Previous § 3179.103 provided for up to 270 cumulative royalty-free production testing days for exploratory coalbed methane wells, whereas the final rule contains no special provision for such wells. Exploratory coalbed methane wells are expected to be an exceedingly low percentage of future wells drilled, and so the BLM does not believe that a special provision addressing these wells is necessary.[34] In the future, if an exploratory coalbed methane well requires additional time for initial production testing, this can be handled under final § 3179.101(b), which allows an operator to request a longer test period without imposing an outside limit on the length of the additional test period the BLM might approve.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.101 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.102 Subsequent well tests.

As proposed, final § 3179.102(a) provides that gas flared during well tests subsequent to the initial production test is royalty free for a period not to exceed 24 hours, unless the BLM approves or requires a longer test period. Also as proposed, final

[34] Exploratory coalbed methane (CBM) well completions have declined precipitously over the past 15 years, likely due to the drop in natural gas prices and the relative attractiveness of natural gas from shale formations. In 2004, the number of exploratory CBM well completions was 904, while in 2015, 2016, 2017, and 2018, the number of CBM well completions on Federal lands was 9, 8, 1, and 1, respectively. Meaning, from 2004 to 2018, exploratory CBM well completions on Federal lands dropped by 99.9%.

§ 3179.102(b) provides that the operator may request a longer test period and must submit its request using a Sundry Notice. Final § 3179.102 is functionally identical to previous § 3179.104.

NTL-4A included royalty-free provisions for "evaluation tests" and for "routine or special well tests." Because NTL-4A also contained specific provisions for "initial production tests," all of the other mentioned tests were presumed to be subsequent to the initial production tests. Under NTL-4A, royalty-free evaluation tests were limited to 24 hours, with no mention of a possibility for extension. Routine or special well tests, which are well tests other than initial production tests and evaluation tests, were royalty free under NTL-4A, but only after approval by the BLM.

The provisions for subsequent well tests in final § 3179.102 are essentially the same as those in both the 2016 rule and in NTL-4A. All three provide for a base test period of 24 hours, and all three have a provision for the BLM to approve a longer test period. Final § 3179.102 improves upon NTL-4A by dispensing with the distinction between "evaluation tests" and "routine or special well tests," making the requirements for subsequent well tests more clear.

The comments about this section that the BLM received expressed support for the provision, as summarized in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.103 Emergencies.

Under final § 3179.4(b)(2)(vi), royalty is not due on gas that is lost during an emergency. As proposed, final § 3179.103 describes the conditions that constitute an emergency, and lists circumstances that do not constitute an emergency. As provided in final § 3179.103(d), an operator is required to estimate and report to the BLM on a Sundry Notice the volumes of gas that were flared or vented beyond the timeframe for royalty-free flaring under final § 3179.103(a) (i.e., venting or flaring beyond 24 hours, or a longer necessary period as determined by the BLM).

The provisions in final § 3179.103 are nearly identical to those in previous § 3179.105. The most notable change from the 2016 rule is in describing those things that do not constitute an emergency. Where previous § 3179.105(b)(1) specifies that "more than 3 failures of the same component within a single piece of equipment within any 365-day period" is not an emergency, final § 3179.103(c)(4) simplifies that concept by including "recurring equipment failures" among the situations caused by operator negligence that do not constitute an emergency. This simplification addresses the practical difficulties involved in tracking the number of times the failure of a specific component of a particular piece of equipment causes emergency venting or flaring, and recognizes that recurring failures of the same equipment, even if involving different "components," may not constitute a true unavoidable emergency.

The description of "emergencies" in NTL-4A was brief and was subject to misinterpretation. The purpose behind both previous § 3179.105 and final § 3179.103 is to improve upon NTL-4A by narrowing the meaning of "emergency," such that it is uniformly understood and consistently applied.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.103 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents.).

43 CFR 3179.104 Downhole well maintenance and liquids unloading.

Under final § 3179.4(b)(2)(viii), gas lost in the course of downhole well maintenance and/or liquids unloading performed in compliance with final § 3179.104 is royalty free. Final § 3179.104(a) states that gas vented or flared during downhole well maintenance and well purging is royalty free for a period not to exceed 24 hours. Final § 3179.104(a) also states that gas vented from a plunger lift system and/or an automated well control system is royalty free. Final § 3179.104(b) states that the operator must minimize the loss of gas associated with downhole well maintenance and liquids unloading, consistent with safe operations. Final § 3179.104(c) states that, for wells equipped with a plunger lift system or automated control system, minimizing gas loss under paragraph (b) includes optimizing the operation of the system to minimize gas losses to the extent possible consistent with removing liquids that would inhibit proper function of the well. Final § 3179.104(d) provides that the operator must ensure that the person conducting manual well purging remains present on-site throughout the event in order to end the event as soon as practical, thereby minimizing any venting to the atmosphere. Final § 3179.104(e) defines "well purging" as blowing accumulated liquids out of a wellbore by reservoir gas pressure, whether manually or by an automatic control system that relies on real-time pressure or flow, timers, or other well data, where the gas

is vented to the atmosphere, and it does not apply to wells equipped with a plunger lift system. Final § 3179.104(e) is identical to previous § 3179.204(g).

Previous § 3179.204 required the operator to "minimize vented gas" in liquids unloading operations, but did not impose volume or duration limits. As with final § 3179.104, previous § 3179.204 allowed for gas vented or flared during well purging to be royalty free provided that the operator ensured that the person conducting the operation remained on-site throughout the event. Previous § 3179.204 also required plunger lift and automated control systems to be optimized to minimize gas loss associated with their effective operation. The main difference between previous § 3179.204 and final § 3179.104 is that previous § 3179.204(c) required the operator to file a Sundry Notice with the BLM the first time that each well was manually purged or purged with an automated control system. That Sundry Notice was required to include documentation showing that the operator evaluated the feasibility of using methods of liquids unloading other than well purging and that the operator determined that such methods were either unduly costly or technically infeasible. In addition to the apparent administrative burden of filing the Sundry Notice, this would have imposed additional costs on the operator by requiring it to evaluate and analyze other methods of liquids unloading. And, the evaluation may have led the operator to identify a more costly alternative that could not be ignored as "unduly costly." Additionally, under previous § 3179.204, the operator would file a Sundry Notice with the BLM each time a well-purging event exceeded either a duration of 24 hours in a month or an estimated gas loss of 75 Mcf in a month. For each manual purging event, the operator would also have needed to keep a record of the cause, date, time, duration, and estimate of the volume of gas vented. The operator

would have had to maintain these records and make them available to the BLM upon request.

With respect to royalty, gas vented during well purging was addressed in NTL-4A as follows: "... operators are authorized to vent or flare gas on a short-term basis without incurring a royalty obligation . . . during the unloading or cleaning up of a well during . . . routine purging . . . not exceeding a period of 24 hours." As used in NTL-4A, it is unclear whether the "24 hours" limit was intended to be 24 hours per month or 24 hours per purging event. In this final rule, the BLM has modified proposed § 3179.104(a) to make clear that it imposes a 24-hour limit per event.

The available data show that the frequency of liquids unloading maintenance operations vary and that the events are relatively short in duration. A study by Shires and Lev-On[35] examined data from an API and American Natural Gas Alliance (ANGA) nationwide survey. The researchers found that, of the roughly 6,500 surveyed wells that vented to the atmosphere for liquids unloading (i.e., not equipped with a plunger lift), the wells required an average of 32.57 events per year for an average of 1.9 hours per event.[36] A study by Allen et al.[37] examined a small sample of nine wells conducting manual well liquids unloading and found that the wells in the sample required an average of 5.9 events per year for an average of 1 hour per event.[38] While the BLM has finalized a 24-hour limit recognizing that certain instances or wells might require maintenance operations that exceed the averages noted, the BLM notes that the rule requires the

[35] Shires, T. & Lev-On, M. (2012). Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses. September 2012.
[36] See Table 7 on p. 15.
[37] Allen, D., Torres, V., et al. (2013). Measurements of methane emissions at natural gas production sites in the United States. Proceedings of the National Academy of Sciences or the United States of America.
[38] See appendix to study at S-37.

person conducting manual well purging to remain present on-site throughout the event to end the event as soon as practical. Therefore, even though the 24-hour limit exceeds the average, we are convinced that the duration of events will be limited to the time necessary.

In terms of minimizing the loss of gas during well-purging events, final § 3179.104 and previous § 3179.204 are essentially the same. Differences between the two are found in the reporting and recordkeeping requirements imposed by the 2016 rule. The intent of these recordkeeping requirements, as explained in the 2016 rule preamble, was to build a record of the amount of gas lost through these operations so that information might lead to better future management of liquids unloading operations. The BLM now believes that the reporting and recordkeeping requirements in previous § 3179.204 are unnecessary and unduly burdensome. In particular, the reporting requirement of previous § 3179.204(c) appears to be unnecessary because wells undergoing manual well purging are mature and the well pressure is in decline[39] and alternative methods of liquids unloading are likely to be costly for those wells.[40] And in light of the economic and production circumstances faced by wells undergoing manual well purging, the BLM does not realistically foresee the development of better waste-management techniques based on manual well-purging information collected pursuant to previous § 3179.204.

As mentioned above, final § 3179.104(d) requires the person conducting manual well purging to remain present on-site throughout the event to end the event as soon as

[39] EPA (2014). Oil and Natural Gas Sector Liquids Unloading Process: Report for Oil and Natural Gas Sector Liquids Unloading Process Review Panel. April 2014. pp. 2, 25.
[40] Ibid. pp. 16-19 of that report detail the costs of various possible interventions.

practical. This provision was not a requirement in NTL-4A, and was first established in the 2016 rule.

The comments about section that the BLM received expressed support for the provision, as summarized in a separate “Responses to Comments” document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter “RIN 1004-AE53,” click the “Search” button, open the Docket Folder, and look under Supporting Documents.).

Other Venting or Flaring

43 CFR 3179.201 Oil-well gas.

As proposed, final § 3179.201 governs the routine flaring of associated gas from oil wells. The requirements of final § 3179.201 replace the “capture percentage” requirements of the 2016 rule. Short-term flaring, such as that experienced during initial production testing, subsequent well testing, emergencies, and downhole well maintenance and liquids unloading, are governed by final §§ 3179.101 through 3179.104.

Final § 3179.201(a) allows operators to vent or flare oil-well gas royalty free when the venting or flaring is done in compliance with applicable rules, regulations, or orders of the State regulatory agency (for Federal gas) or tribe (for Indian gas). This section establishes State or tribal rules, regulations, and orders as the prevailing regulations for the venting and flaring of oil-well gas on BLM-administered leases, unit participating areas (PAs), or communitization agreements (CAs).

Under the 2016 rule, an operator’s royalty obligations for venting or flaring were determined by the avoidable/unavoidable loss definitions and the gas-capture-requirement thresholds. Operator royalty obligations for the flaring of associated gas

from oil wells under NTL-4A were, for the most part, dependent on a discretionary authorization by the BLM based on the economics of gas capture or an action plan to eventually eliminate the flaring. NTL-4A also allowed for gas to be flared royalty free pursuant to the rules, regulations, or order of the appropriate State regulatory agency, when the BLM had ratified or accepted such rules, regulations, or orders. The final rule implements this concept from NTL-4A by deferring to the rules, regulations, or orders of State regulatory agencies or a tribe. This change both simplifies an operator's obligations by aligning Federal and State venting and flaring requirements for oil-well gas and allows for region-specific regulation of oil-well gas that accounts for regional differences in production, markets, and infrastructure. An operator owes royalty on any oil-well gas flared in violation of applicable State or tribal requirements.

The BLM has analyzed the statutory and regulatory restrictions on venting and flaring in the 10 States constituting the top eight producers of Federal oil and the top eight producers of Federal gas, which collectively produce more than 99 percent of Federal oil and more than 98 percent of Federal gas. The BLM found that each of these States have statutory or regulatory restrictions on venting and flaring that are expected to constrain the waste of associated gas from oil wells. Most of these States require an operator to obtain approval from the State regulatory authority (by justifying the need to flare) in order to engage in the flaring of associated gas.[41] North Dakota has a similar requirement, but, in the Bakken, Bakken/Three Forks, and Three Forks pools, restricts flaring through the application of gas-capture goals that function similarly to the capture percentage requirements of the 2016 rule. Summaries of the State statutory and

[41] These States are: New Mexico, Wyoming, Colorado, Utah, Montana, Texas, and Oklahoma.

regulatory restrictions on venting and flaring analyzed by the BLM are contained in a Memorandum that BLM has published for public access on https://www.regulations.gov. (In the Searchbox, enter “RIN 1004-AE53,” click the “Search” button, open the Docket Folder, and look under Supporting Documents). Final § 3179.201(a) defers to State and tribal statutes and regulations, like those described in the Memorandum, that provide a reasonable assurance to the BLM that operators will not be permitted to engage in the flaring of associated gas without limitation and that the waste of associated gas will be controlled. In order to make this clear in the final regulatory text, the BLM has chosen to add the following language to the text of proposed § 3179.201(a): “Applicable State or tribal rules, regulations, or orders are appropriate if they place limitations on the venting and flaring of oil-well gas, including through general or qualified prohibitions, volume or time limitations, capture percentage requirements, or trading mechanisms.”

Some commenters expressed support for the deference to State and tribal regulations in § 3179.201(a). These commenters noted that the various oil and gas fields throughout the country possess different geological characteristics and that the primary fossil fuel resources extracted from the fields vary in type and quality. These commenters expressed support for § 3179.201(a) because it accounts for these regional differences. The BLM agrees with these commenters that regional geological differences make it difficult to develop a single standard for oil-well gas flaring that will be fair and effective when applied nationwide.

Other commenters objected to § 3179.201(a) on the grounds that State flaring regulations are less stringent than the 2016 rule, that State flaring regulations differ from State to State, that existing State regulations will not reduce flaring from current levels,

that States may amend their regulations, and that North Dakota's flaring regulations have been, in the view of the commenters, ineffective. The BLM agrees that many of the State regulations it analyzed are not as stringent as the capture percentage requirements of the 2016 rule and that State flaring regulations vary from State to State. However, the BLM disagrees that this represents a flaw in § 3179.201(a). As explained above and evidenced by the 2016 RIA, BLM expected the capture percentage requirements of the 2016 rule to impose net costs. In § 3179.201(a), the BLM is replacing a regulatory requirement that imposed unreasonable costs with a policy that will reasonably constrain waste while accounting for the differing geological and infrastructure realities faced by operators in different regions. The BLM does not argue that each State's existing flaring regulations will necessarily reduce flaring rates in that State. However, this does not mean that the BLM is acting unreasonably or in violation of its statutory obligations in deferring to them under § 3179.201(a). As explained above, after reviewing the State regulations for the 10 states producing approximately 99 percent of Federal oil and gas, the BLM believes that these regulations require operators to take reasonable precautions to prevent undue waste. The BLM also recognizes that States may amend their regulations. If such an amendment were to propose a relaxation of a State's restrictions on flaring, and the BLM judged that it allowed for undue waste of Federal gas, then the BLM would move swiftly to amend § 3179.201 to preclude deference to that State's flaring regulations.

With respect to the efficacy of North Dakota's regulations, commenters submitted tabular data indicating that, of the top 30 producers of gas in the Bakken/Bakken-Three Forks/Three-Forks pools, 19 exceeded the applicable flaring percentage requirement in at least one month in 2017. The table submitted by the commenters highlighted each month

in which an operator failed to meet the applicable capture target of 85 percent. The BLM notes that the table indicates that in many of these instances the operator appears to have narrowly missed the requirement (e.g., capturing 84 percent instead of 85 percent). The BLM further notes that, for all but five or six of the 30 operators, the failure to meet the monthly capture target was an occasional, rather than routine, issue. The table submitted by commenters shows that: 11 of the 30 operators met their capture target for every month in 2017; 5 of the 30 operators failed to meet their capture target in only 1 month in 2017; and 5 of the 30 operators failed to meet their capture target in only 2 months in 2017. The BLM does not believe that these statistics indicate that North Dakota's flaring regulations are deficient. Commenters also claimed that North Dakota has been derelict in taking enforcement actions against operators that fail to meet the capture target. However, the extent of a State's enforcement of its regulations does not impact whether flared gas is royalty bearing under § 3179.201(a). If the flaring violates the applicable State regulation, it will be royalty bearing regardless of whether the State takes enforcement action. Finally, the BLM estimates that the flaring of Federal and Indian mineral estate oil-well gas in North Dakota has been reduced substantially from 64 Bcf in 2015 to 44 Bcf in 2016.

Final § 3179.201(b) exclusively addresses oil-well gas production from an Indian lease. Vented or flared oil-well gas from an Indian lease will be treated as royalty free pursuant to final § 3179.201(a) only to the extent it is consistent with the BLM's trust responsibility.

In the event a State regulatory agency or tribe does not currently have rules, regulations, or orders governing venting or flaring of oil-well gas, the BLM is retaining

the NTL-4A approach as a backstop, providing a way for operators to obtain BLM approval to vent or flare oil-well gas royalty free by submitting an application with sufficient justification as described in final §3179.201(c). Applications for royalty-free venting or flaring of oil-well gas must include either: (1) An evaluation report supported by engineering, geologic, and economic data demonstrating that capturing or using the gas is not economical; or (2) An action plan showing how the operator will minimize the venting or flaring of the gas within 1 year of the application. If an operator vents or flares oil-well gas in excess of 10 MMcf per well during any month, the BLM may determine the gas to be avoidably lost and subject to royalty assessment. The BLM notes that there was no similar provision in NTL-4A allowing for the BLM to impose royalties where flaring under an action plan exceeds 10 MMcf per well per month. However, this provision is based on guidance in the Conservation Division Manual[42] (at 644.5.3F), which was developed by the USGS and has long been used by the BLM as implementation guidance for NTL-4A.

As under NTL-4A, the evaluation report required under final § 3179.201(c)(1) must demonstrate to the BLM's satisfaction that the expenditures necessary to market or beneficially use the gas are not economically justified. Under final § 3179.201(d)(1), the evaluation report must include estimates of the volumes of oil and gas that would be produced to the economic limit if the application to vent or flare were approved, and estimates of the volumes of oil and gas that would be produced if the applicant was required to market or use the gas.

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[42] Available at https://www.ntc.blm.gov/krc/uploads/172/NTL-4A%20Royalty%20or%20Compensation%20for%20Oil%20and%20Gas%20Lost.pdf

From the information contained in the evaluation report, the BLM will determine whether the operator can economically operate the lease if it is required to market or use the gas, taking into consideration both oil and gas production, as well as the economics of a field-wide plan. Under final § 3179.201(d)(2), the BLM is able to require operators to provide updated evaluation reports as additional development occurs or economic conditions improve, but no more than once a year. NTL-4A did not contain a similar provision allowing the BLM to require an operator to update its evaluation report based on changing circumstances. Final § 3179.201(d)(2) thus represents a change from NTL-4A.

An action plan submitted under final § 3179.201(c)(2) must show how the operator will minimize the venting or flaring of the oil-well gas within 1 year. An operator may apply for an approval of an extension of the 1-year time limit. In the event the operator fails to implement the action plan, the entire volume of gas vented or flared during the time covered by the action plan would be subject to royalty.

Final § 3179.201(e) provides for grandfathering of prior approvals to flare royalty free. These approvals will continue in effect until no longer necessary because the venting or flaring is authorized by the rules, regulations, or orders of an appropriate State regulatory agency or tribe under final § 3179.201(a), or the BLM requires an updated evaluation report and determines to amend or revoke its approval.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.201 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*:

https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents).

Measurement and Reporting Responsibilities

43 CFR 3179.301 Measuring and reporting volumes of gas vented and flared.

As proposed, final § 3179.301(a) requires operators to estimate or measure all volumes of lost oil and gas, whether avoidably or unavoidably lost, from wells, facilities, and equipment on a lease, unit PA, or CA and report those volumes under applicable Office of Natural Resources Revenue (ONRR) reporting requirements. Under final § 3179.301(b), the operator may: (1) Estimate or measure the vented or flared gas in accordance with applicable rules, regulations, or orders of the appropriate State or tribal regulatory agency; (2) Estimate the volume of the vented or flared gas based on the results of a regularly performed GOR test and measured values for the volume of oil production and gas sales, to allow BLM to independently verify the volume, rate, and heating value of the flared gas; or, (3) Measure the volume of the flared gas.

Under final § 3179.301(c), the BLM may require the installation of additional measurement equipment whenever it determines that the existing methods are inadequate to meet the purposes of subpart 3179. NTL-4A contained essentially the same provision. Based on past experience in implementing NTL-4A, the BLM believes that final § 3179.301(c) would help to ensure accuracy and accountability in situations in which high volumes of royalty-bearing gas are being flared.

Final § 3179.301(d) allows the operator to combine gas from multiple leases, unit PAs, or CAs for the purpose of flaring or venting at a common point, but the operator is required to use a BLM-approved method to allocate the quantities of the vented or flared

gas to each lease, unit PA, or CA. Commingling to a single flare is allowed because the BLM recognizes that the additional costs of requiring individual flaring measurement and meter facilities for each lease, unit PA, or communitized area are not necessarily justified by the incremental royalty accountability afforded by the separate meters and flares.

Final § 3179.301 is essentially the same as previous § 3179.9. The main difference between the two is that previous § 3179.9 required measurement or calculation under a particular protocol when the volume of flared gas exceeded 50 Mcf per day.

In addition to the explanation provided here, the BLM has summarized and responded to the comments received on § 3179.301 in a separate "Responses to Comments" document, available on the *Federal eRulemaking Portal*: https://www.regulations.gov (In the Searchbox, enter "RIN 1004-AE53," click the "Search" button, open the Docket Folder, and look under Supporting Documents).

Additional Deference to Tribal Regulations

§ 3179.401 Deference to Tribal Regulations.

Tribal commenters stated that the revision of the 2016 rule should provide more opportunity for tribes to exercise their sovereignty over oil and gas development under their jurisdiction. In order to facilitate this, the BLM has chosen to modify the proposed rule to include a new provision that would allow for additional deference to Tribal rules, regulations, and orders concerning the matters addressed in subpart 3179. New § 3179.401(a) states that "[a] Tribe that has rules, regulations, or orders that are applicable to any of the matters addressed in subpart 3179 may seek approval from the BLM to have such rules, regulations, or orders apply in place of any or all of the provisions of subpart 3179 with respect to lands and minerals over which that Tribe has jurisdiction." Under §

3179.401(b), the BLM will approve the tribe's request as long as it is consistent with the BLM's trust responsibility.

C. Summary of Estimated Impacts

The BLM reviewed the final rule and conducted an RIA and Environmental Assessment (EA) that examine the impacts of the final rule's requirements. The RIA and EA that the BLM prepared have been posted in the docket for the final rule on the *Federal eRulemaking Portal*: https://www.regulations.gov. (In the Searchbox, enter "RIN 1004-AE53", click the "Search" button, open the Docket Folder, and look under Supporting Documents). The following discussion is a summary of the final rule's economic impacts. For a more complete discussion of the expected economic impacts of the final rule, please review the RIA.

The BLM's final rule will remove almost all of the requirements in the 2016 rule that we previously estimated would pose a compliance burden to operators and generate benefits of gas savings or reductions in methane emissions. The final rule replaces the 2016 rule's requirements with requirements largely similar to those that were in NTL-4A. Also, for the most part, the final rule removes the administrative burdens associated with the 2016 rule's subpart 3179.

In conducting this RIA, the BLM also revisited the underlying assumptions used in the RIA for the 2016 rule. Specifically, the BLM revisited the underlying assumptions pertaining to LDAR, administrative burdens, and climate benefits (see Sections 3.2, 3.3, and 7 of the RIA).

For this final rule, we track the impacts over the first 10 years of implementation against the baseline. The period of analysis in the RIA prepared for the 2016 rule was 10

years. Results are provided using the net present value (NPV) of costs and benefits estimated over the evaluation period, calculated using 7 percent and 3 percent discount rates.

<u>Estimated Reductions in Compliance Costs</u>

First, we examined the reductions in compliance costs, excluding the savings that would have been realized from product recovery. The final rule reduces compliance costs from the baseline. Over the 10-year evaluation period (2019-2028), we estimate a total reduction in compliance costs of $1.36 billion to 1.63 billion (NPV using a 7 percent discount rate) or $1.71 billion to 2.08 billion (NPV using a 3 percent discount rate). We expect very few compliance costs associated with the final rule, including the remaining administrative burdens.

<u>Estimated Reduction in Benefits</u>

The final rule reduces benefits from the baseline, since estimated cost savings that would have come from product recovery will be forgone and the emissions reductions would also be forgone. The final rule will result in forgone cost savings from natural gas recovery. Over the 10-year evaluation period (2019-2028), we estimate total forgone cost savings from natural gas recovery (from the baseline) of $559 million (NPV using a 7 percent discount rate) or $734 million (NPV using a 3 percent discount rate). The final rule also expects to result in forgone methane emissions reductions. Over the 10-year evaluation period (2019-2028), we estimate total forgone methane emissions reductions from the baseline valued at $66 million (NPV and interim domestic SC-CH4 using a 7 percent discount rate) or $259 million (NPV and interim domestic SC-CH4 using a 3 percent discount rate).

Estimated Net Benefits

The final rule is estimated to result in positive net benefits relative to the baseline. More specifically, we estimate that the reduction of compliance costs will exceed the forgone cost savings from recovered natural gas and the value of the forgone methane emissions reductions. Over the 10-year evaluation period (2019-2028), we estimate total net benefits from the baseline of $734 million to $1.01 billion (NPV and interim domestic SC-CH_4 using a 7 percent discount rate) or $720 million to $1.08 billion (NPV and interim domestic SC-CH_4 using a 3 percent discount rate).

Energy Systems

The final rule is expected to influence the production of natural gas, natural gas liquids, and crude oil from onshore Federal and Indian oil and gas leases. However, since the relative changes in production are expected to be small, we do not expect that the final rule will significantly impact the price, supply, or distribution of energy. This is not to say that the rule would not have a positive effect on marginal wells and the production of oil and natural gas from marginal wells.

The BLM conducted an analysis to examine the impacts that the 2016 rule would have had on marginal wells. As described in Section II.b of this preamble and Section 4.5.6 of the RIA, the BLM estimates that approximately 73 percent of wells on BLM-administered leases are considered to be marginal wells and that the annual compliance costs associated with the 2016 rule would have constituted 24 percent of the annual revenues of even the highest-producing marginal oil wells and 86 percent of the annual revenues of the highest-producing marginal gas wells. Production from marginal wells represents a smaller fraction of total oil and gas production than that of non-marginal

wells. However, as the BLM's analysis indicates, this means that any associated regulatory burdens would have a disproportionate impact on marginal wells, since the compliance costs represent a much higher fraction of oil and gas revenues for marginal wells than they do for non-marginal wells. Thus, the compliance burdens of the 2016 rule pose a greater cost to marginal well producers.

The BLM also finds that marginal oil and gas production on Federal lands supported an estimated $2.9 billion in economic output in the national economy in FY 2015. To the extent that the 2016 rule would have adversely impacted production from marginal wells through premature shut-ins, this estimated economic output would have been jeopardized. Therefore, while the BLM has determined that the 2018 final rule would not significantly impact the price, supply, or distribution of energy, the BLM acknowledges that the 2016 rule had the potential to harm the production of oil and natural gas from marginal wells and that this revision of the 2016 rule would avoid those potentially harmful effects.

The final rule will reverse the estimated incremental changes in crude oil and natural gas production associated with the 2016 rule. Over the 10-year evaluation period (2019-2028), we estimate that 18.4 million barrels of crude oil production and 22.7 Bcf of natural gas production will no longer be deferred (as it would have been under the 2016 rule). However, we also estimate that there will be 299 Bcf of forgone natural gas production (that would have been produced and sold under the 2016 rule, rather than vented or flared). See RIA at Section 4.5.1.

For context, we note the share of the total U.S. onshore production in 2015 that the incremental changes in production will represent. The per-year average of the

estimated crude oil volume that will no longer be deferred represents 0.058 percent of the total onshore U.S. crude oil production in 2015.[43] The per-year average of the estimated natural gas volume that will no longer be deferred represents 0.008 percent of the total onshore U.S. natural gas production in 2015.[44] The per-year average of the estimated forgone natural gas production represents 0.109 percent of the total onshore U.S. natural gas production in 2015.[45]

Royalty Impacts

The 2016 rule would have been expected to impact the production of crude oil and natural gas from Federal and Indian oil and gas leases. In the RIA for the 2016 rule, the BLM estimated that the rule's requirements would generate additional natural gas production, but that substantial volumes of crude oil production would be deferred or shifted to the future. The BLM concluded that the 2016 rule would generate overall additional royalty, with the royalty gains from the additional natural gas produced outweighing the value of the royalty losses from crude oil production (and some associated gas) being deferred into the future.

This final rule, which reverses most of the 2016 rule's provisions, is expected to reverse the estimated royalty impacts of the 2016 rule. This formulation does not account for the potential countervailing impacts of the reduction in compliance burdens, which might spur additional production on Federal and Indian lands and prolong production from marginal wells, and therefore have a positive impact on royalties.

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[43] Calculation based on total onshore U.S. crude oil production in 2015, as reported by the U.S. EIA. Production data available at https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.

[44] Calculation based on total onshore U.S. natural gas and gross withdrawals in 2015, as reported by the U.S. EIA. Production data available at https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm.

[45] Ibid.

We note that royalty impacts are presented separately from the costs, benefits, and net benefits. Royalty payments are recurring income to Federal or tribal governments and costs to the operator or lessee. As such, they are transfer payments that do not affect the total resources available to society. An important but sometimes difficult problem in cost estimation is to distinguish between real costs and transfer payments. While transfers should not be included in the economic analysis estimates of the benefits and costs of a regulation, they may be important for describing the distributional effects of a regulation.

The final rule will result in forgone royalty payments to the Federal Government, tribal governments, States, and private landowners. Over the 10-year evaluation period (2019-2028), we estimate total forgone royalty payments (from the baseline) of $28.3 million (NPV using a 7 percent discount rate) or $79.1 million (NPV using a 3 percent discount rate).

Consideration of Alternative Approaches

E.O. 13563 reaffirms the principles of E.O. 12866 and requires that agencies, among other things, "identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public."

The 2016 rule established requirements and direct regulation on operators. Under this final rule, the BLM will remove the requirements of the 2016 rule that impose the most substantial direct regulatory burdens on operators. Also, with the final rule, the BLM will remove the duplicative operational and equipment requirements and paperwork and administrative burdens.

In developing this final rule, the BLM considered scenarios for retaining certain requirements previously contained in subpart 3179. For example, we examined the impacts of retaining subpart 3179 in its entirety (essentially taking no action). We also examined the impacts of retaining the gas-capture requirements of the 2016 rule (previous §§ 3179.7 - 3179.8) and the measurement/metering requirements (previous § 3179.9) while rescinding the operational and equipment requirements addressing venting from leaks, pneumatic equipment, and storage tanks. The results of these alternative scenarios are presented in the RIA at Section 4.

Employment Impacts

E.O. 13563 reaffirms the principles established in E.O. 12866, but calls for additional consideration of the regulatory impact on employment. E.O. 13563 states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." An analysis of employment impacts is a standalone analysis and the impacts should not be included in the estimation of benefits and costs.

This final rule removes or replaces requirements of the BLM's 2016 rule on waste prevention and is a deregulatory action. As such, we estimate that it will result in a reduction of compliance costs for operators of oil and gas leases on Federal and Indian lands. Therefore, it is likely that the impact, if any, on employment will be positive.

In the RIA for the 2016 rule, the BLM concluded that the requirements were not expected to impact the employment within the oil and gas extraction, drilling oil and gas wells, and support activities industries, in any material way. This determination was based on several reasons. First, the estimated incremental gas production represented only

a small fraction of the U.S. natural gas production volumes. Second, the estimated compliance costs represented only a small fraction of the annual net incomes of companies likely to be impacted. Third, for those operations that would have been impacted, the 2016 rule had provisions that would exempt these operations from compliance to the extent that the compliance costs would force the operator to shut in production. Based on these factors, the BLM determined that the 2016 rule would not alter the investment or employment decisions of firms or significantly adversely impact employment. The RIA also noted that the requirements would necessitate the one-time installation or replacement of equipment and the ongoing implementation of an LDAR program, both of which would require labor.

By removing or revising the requirements of the 2016 rule, the BLM is alleviating the associated compliance burdens on operators. The investment and labor necessary to comply with the 2016 rule will not be needed. We do not believe that the cost savings in themselves will be substantial enough to substantially alter the investment or employment decisions of firms. However, we also recognize that there may be a small positive impact on investment and employment due to the reduction in compliance burdens if the output effects dominate. The magnitude of the reductions will be relatively small but could carry competitiveness impacts, specifically on marginal wells on Federal lands, encouraging investment. In sum, the effect on investment and employment of this rule remains unknown, but we do not believe that the final rule will substantially alter the investment or employment decisions of firms.

Small Business Impacts

The BLM reviewed the Small Business Administration (SBA) size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau. We conclude that small entities represent the majority of entities operating in the onshore crude oil and natural gas extraction industry and, therefore, the final rule will impact a substantial number of small entities. To examine the economic impact of the rule on small entities, the BLM performed a screening analysis on a sample of potentially affected small entities, comparing the reduction of compliance costs to entity profit margins. This screening analysis showed that the estimated per-entity reduction in compliance costs would result in an average increase in profit margin of 0.19 percentage points (based on the 2014 company data).[46]

The BLM performed the screening analysis pursuant to its obligations under the Regulatory Flexibility Act and the Small Business Regulatory Enforcement Fairness Act. The BLM recognizes that there are many operators of Federal and Indian leases that are substantially smaller than the SBA size standards for small businesses in the affected industries.[47] For these smaller operators, the estimated reduction in compliance costs would result in a larger increase in profits than the average increase shown above.

The BLM also notes that most of the emissions-based requirements in the 2016 rule (including LDAR, pneumatic controllers, pneumatic pumps, and liquids unloading requirements) would have imposed a particular burden on marginal or low-producing

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[46] Average commodity price in 2014 was higher than subsequent years; therefore, the result in profit margin may not be representative of the increase in profit margin as a result of the updated rulemaking.

[47] This rule directly affects entities classified within the Crude Petroleum and Natural Gas Extraction (North American Industry Classification System (NAICS) code 211111), Natural Gas Liquid Extraction (NAICS code 211112), Drilling of Oil and Natural Gas Wells (NAICS code 213111), and Support Activities for Oil and Gas Operations (213112) industries. The SBA size standards for these industries are 1,250 employees, 1,000 employees, and annual receipts of less than $38.5 million, respectively.

wells.[48] There is concern that those wells would not have been able to be operated profitably with the additional compliance costs imposed by the 2016 rule. While the 2016 rule allows for exemptions when compliance would impose such costs that the operator would cease production and abandon significant recoverable reserves, due to the prevalence of marginal and low-producing wells, the BLM expects that many exemptions would have been warranted, making the burdens imposed by the exemption process, in itself, excessive. The prospect of either shutting-in a marginal well or assuming unwarranted administrative burdens to avoid compliance costs potentially represented a substantial loss of income for companies operating marginal wells. The BLM's final rule rescinds or revises these requirements in the 2016 rule, thus reducing compliance costs for all wells, including marginal wells, and reducing the potential economic harm to small businesses.

Impacts Associated with Oil and Gas Operations on Tribal Lands

The final rule applies to oil and gas operations on both Federal and Indian leases. In the RIA, the BLM estimates the impacts associated with operations on Indian leases, as well as royalty implications for tribal governments. We estimate these impacts by scaling down the total impacts by the share of oil wells on Indian lands and the share of gas wells on Indian Lands. Please reference the RIA at Section 4.4.5 for a full explanation of the estimated impacts.

IV. Procedural Matters

Regulatory Planning and Review (E.O. 12866, E.O. 13563)

[48] As explained previously, the IOGCC defines a marginal well as one that produces 10 barrels of oil or 60 Mcf of natural gas per day or less and reports that about 69.1 and 75.9 percent of the Nation's operating oil and gas wells, respectively, are marginal. EIA estimates that 73.3 percent of wells are marginal.

Executive Order 12866 provides that the Office of Information and Regulatory Affairs within the Office of Management and Budget (OMB) will review all significant rules. The Office of Information and Regulatory Affairs has determined that this final rule is economically significant because it will:

- Have an annual effect of $100 million or more on the economy; and
- Raise novel legal or policy issues.

Executive Order 13563 reaffirms the principles of Executive Order 12866 while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The Executive Order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. Executive Order 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this rule in a manner consistent with these requirements.

This final rule rescinds or revises portions of the BLM's 2016 rule. We have developed this final rule in a manner consistent with the requirements in Executive Order 12866 and Executive Order 13563.

The BLM reviewed the requirements of the final rule and determined that it will not adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. For more detailed information, see the RIA

prepared for this final rule. The RIA has been posted in the docket for the proposed rule on the Federal eRulemaking Portal: https://www.regulations.gov. (In the Searchbox, enter "RIN 1004-AE53", click the "Search" button, open the Docket Folder, and look under Supporting Documents).

Reducing Regulation and Controlling Regulatory Costs (E.O. 13771)

This final rule is expected to be an E.O. 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in the rule's RIA.

Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) (RFA) generally requires that Federal agencies prepare a regulatory flexibility analysis for rules subject to the notice-and-comment rulemaking requirements under the Administrative Procedure Act (5 U.S.C. 500 *et seq.*), if the rule would have a significant economic impact, whether detrimental or beneficial, on a substantial number of small entities. *See* 5 U.S.C. 601 – 612. Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The BLM reviewed the SBA size standards for small businesses and the number of entities fitting those size standards as reported by the U.S. Census Bureau in the Economic Census. The BLM concludes that the vast majority of entities operating in the relevant sectors are small businesses as defined by the SBA. As such, the final rule will likely affect a substantial number of small entities.

The BLM reviewed the final rule and estimates that it will generate cost savings of about $72,000 per entity per year. These estimated cost savings will provide relief to

small operators, which, the BLM notes, represent the overwhelming majority of operators of Federal and Indian leases.

For the purpose of carrying out its review pursuant to the RFA, the BLM believes that the final rule will not have a "significant economic impact on a substantial number of small entities," as that phrase is used in 5 U.S.C. 605. An initial regulatory flexibility analysis is therefore not required. In making a significance determination under the RFA, BLM used an estimated per-entity cost savings to conduct a screening analysis. The analysis shows that the average reduction in compliance costs associated with this final rule are a small enough percentage of the profit margin for small entities, so as not be considered "significant" under the RFA.

Details on this determination can be found in the RIA for the final rule.

Small Business Regulatory Enforcement Fairness Act

This final rule is a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This final rule:

(a) Will have an annual effect on the economy of $100 million or more.

(b) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

(c) Will not have a significant adverse effect on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

Unfunded Mandates Reform Act (UMRA)

This final rule will not impose an unfunded mandate on State, local, or tribal governments, or the private sector of $100 million or more per year. The final rule will not have a significant or unique effect on State, local, or tribal governments or the private sector. The final rule contains no requirements that would apply to State, local, or tribal governments. It will rescind or revise requirements that would otherwise apply to the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1531 *et seq.*) is not required for the final rule. This final rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments, because it contains no requirements that apply to such governments, nor does it impose obligations upon them.

Governmental Actions and Interference with Constitutionally Protected Property Right - Takings (Executive Order 12630)

This final rule would not effect a taking of private property or otherwise have taking implications under Executive Order 12630. A takings implication assessment is not required. The final rule rescinds or revises many of the requirements placed on operators by the 2016 rule. Operators will not have to undertake the associated compliance activities, either operational or administrative. Therefore, the final rule impacts some operational and administrative requirements on Federal and Indian lands. All such operations are subject to lease terms which expressly require that subsequent lease activities be conducted in compliance with subsequently adopted Federal laws and regulations. This final rule conforms to the terms of those leases and applicable statutes and, as such, the rule is not a government action capable of interfering with

constitutionally protected property rights. Therefore, the BLM has determined that the rule will not cause a taking of private property or require further discussion of takings implications under Executive Order 12630.

Federalism (Executive Order 13132)

Under the criteria in section 1 of Executive Order 13132, this final rule does not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement. A federalism impact statement is not required.

The final rule will not have a substantial direct effect on the States, on the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the levels of government. It would not apply to States or local governments or State or local governmental entities. The rule will affect the relationship between operators, lessees, and the BLM, but it does not directly impact the States. Therefore, in accordance with Executive Order 13132, the BLM has determined that this final rule does not have sufficient federalism implications to warrant preparation of a Federalism Assessment.

Civil Justice Reform (Executive Order 12988)

This final rule complies with the requirements of Executive Order 12988. More specifically, this final rule meets the criteria of section 3(a), which requires agencies to review all regulations to eliminate errors and ambiguity and to write all regulations to minimize litigation. This final rule also meets the criteria of section 3(b)(2), which requires agencies to write all regulations in clear language with clear legal standards.

Consultation and Coordination with Indian Tribal Governments (Executive Order 13175 and Departmental Policy)

The Department strives to strengthen its government-to-government relationship with Indian tribes through a commitment to consultation with Indian tribes and recognition of their right to self-governance and tribal sovereignty. We have evaluated this final rule under the Department's consultation policy and under the criteria in Executive Order 13175 and have identified substantial direct effects on federally recognized Indian tribes that will result from this final rule. Under this final rule, oil and gas operations on tribal and allotted lands will no longer be subject to many of the requirements placed on operators by the 2016 rule.

The BLM believes that revising the requirements of subpart 3179 will prevent Indian lands from being viewed as less attractive to oil and gas operators than non-Indian lands due to unnecessary and burdensome compliance costs, thereby preventing economic harm to tribes and allottees. The BLM conducted tribal outreach which it believes is appropriate given that the final rule will remove many of the compliance burdens of the 2016 rule, defer to tribal laws, regulations, rules, and orders, with respect to oil-well gas flaring from Indian leases, and otherwise revise subpart 3179 in a manner that aligns it with NTL-4A.

The BLM is committed to engaging in meaningful Tribal Consultation. Through a letter dated November 21, 2017, the BLM notified 428 Tribal leaders and representatives of its intent to propose a rule to revise the 2016 final rule. In the letter, the BLM offered to participate in government-to-government consultations or to accept for consideration written comments, at the recipient’s convenience. These letters were sent three months before the BLM published the proposed rule in the Federal Register.

The BLM received letters from several tribes seeking government-to-government consultation. The BLM also received comments from three allottees and members of tribes who did not request consultation. In response, the BLM conducted government-to-government consultations with the tribes who had requested consultation. During each of these government-to-government consultations, the BLM discussed the regulatory action with the tribes. The feedback the BLM received was overall positive, particularly about the opportunity for greater tribal sovereignty.

Paperwork Reduction Act

1. Overview

The Paperwork Reduction Act (PRA) (44 U.S.C. 3501–3521) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid control number. 44 U.S.C. 3512. Collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency. 44 U.S.C. 3502(3); 5 CFR 1320.3(c) and (k).

OMB approved 24 information collection activities in the 2016 rule pertaining to waste prevention and assigned control number 1004-0211 to those activities. See ‘‘Waste Prevention, Production Subject to Royalties, and Resource Conservation,’’ Final Rule, 81 FR 83008 (Nov. 18, 2016). In the Notice of Action approving the 24 information collection activities in the 2016 rule, OMB announced that the control number will expire on January 31, 2018. The Notice of Action also included terms of clearance.

On October 5, 2017, the BLM proposed a rule that would suspend or delay several regulations in the 2016 rule. In that proposed rule, the BLM requested the extension of control number 1004-0211 until January 31, 2019, including the 24 information collection activities in the 2016 rule. The BLM invited public comment on the proposed extension of control no. 1004-0211. The BLM also submitted the information collection request for the proposed rule to OMB for review in accordance with the PRA.

The BLM finalized that rule on December 8, 2017. See 82 FR 58050. OMB approved the information collection activities in the rule with an expiration date of December 31, 2020, and with a Term of Clearance that maintains the effectiveness of the Terms of Clearance associated with the 2016 rule. That Term of Clearance requires the BLM to submit to the Office of Information and Regulatory Affairs draft guidance to implement the collection of information requirements of the 2016 rule no later than 3 months after January 17, 2019.

This final rule does not modify any regulations in 43 CFR subpart 3178. Accordingly, the BLM requests continuation of the information collection activity at 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 (“Request for Approval for Royalty-Free Uses On-Lease or Off-Lease”).

The final rule removes the information collection activity at 43 CFR 3162.3-1(j) (“Plan to Minimize Waste of Natural Gas”). The final rule also removes or revises many regulations and information collection activities in 43 CFR subpart 3179. As a result, the BLM now requests revision of control number 1004-0211 to include:

- The information collection activities in this final rule; and

- The information collection activity entitled, “Request for Approval for Royalty-Free Uses On-Lease or Off-Lease.”

2. Summary of Information Collection Activities

Title: Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR parts 3160 and 3170).

OMB Control Number: 1004–0211.

Form: Form 3160–5, Sundry Notices and Reports on Wells.

Description of Respondents: Holders of Federal and Indian (except Osage Tribe) oil and gas leases, those who belong to Federally approved units or communitized areas, and those who are parties to oil and gas agreements under the Indian Mineral Development Act, 25 U.S.C. 2101–2108.

Respondents’ Obligation: Required to obtain or retain a benefit.

Frequency of Collection: On occasion.

Abstract: The BLM requests that control number 1004-0211 be revised to include the information collection activities in this final rule, as well as the information collection activity in 43 CFR subpart 3178 that was in the 2016 rule. The BLM also requests the removal of the information collection activity in 43 CFR 3162.3-1(j) that was in the 2016 rule, and the removal or revision of the information collection activities that were in 43 CFR subpart 3179 of the 2016 rule.

Estimated Number of Responses: 1,075.

Estimated Total Annual Burden Hours: 4,010.

Estimated Total Non-Hour Cost: None.

2. Information Collection Request

A. The BLM requests that OMB control number 1004-0211 continue to include the following information collection activity that was included at 43 CFR subpart 3178 of the 2016 rule: Request for Approval for Royalty-Free Uses On-Lease or Off-Lease (43 CFR 3178.5, 3178.7, 3178.8, and 3178.9)

Section 3178.5 requires submission of a Sundry Notice (Form 3160-5) to request prior written BLM approval for use of gas royalty free for the following operations and production purposes on the lease, unit or communitized area:

- Using oil or gas that an operator removes from the pipeline at a location downstream of the facility measurement point (FMP);
- Removal of gas initially from a lease, unit PA, or communitized area for treatment or processing because of particular physical characteristics of the gas, prior to use on the lease, unit PA or communitized area; and
- Any other type of use of produced oil or gas for operations and production purposes pursuant to § 3178.3 that is not identified in § 3178.4
- Section 3178.7 requires submission of a Sundry Notice (Form 3160-5) to request prior written BLM approval for off-lease royalty-free uses in the following circumstances:
    - The equipment or facility in which the operation is conducted is located off the lease, unit, or communitized area for engineering, economic, resource-protection, or physical-accessibility reasons; and
    - The operations are conducted upstream of the FMP.

Section 3178.8 requires that an operator measure or estimate the volume of royalty-free gas used in operations upstream of the FMP. In general, the operator is free

to choose whether to measure or estimate, with the exception that the operator must in all cases measure the following volumes:

- Royalty-free gas removed downstream of the FMP and used pursuant to §§ 3178.4 through 3178.7; and
- Royalty-free oil used pursuant to §§ 3178.4 through 3178.7.

If oil is used on the lease, unit or communitized area, it is most likely to be removed from a storage tank on the lease, unit or communitized area. Thus, this regulation also requires the operator to document the removal of the oil from the tank or pipeline.

Section 3178.8(e) requires that operators use best available information to estimate gas volumes, where estimation is allowed. For both oil and gas, the operator must report the volumes measured or estimated, as applicable, under ONRR reporting requirements. As revisions to Onshore Oil and Gas Orders No. 4 and 5 have now been finalized as 43 CFR subparts 3174 and 3175, respectively, the final rule text now references § 3173.12, as well as § 3178.4 through § 3178.7 to clarify that royalty-free use must adhere to the provisions in those sections.

Section 3178.9 requires the following additional information in a request for prior approval of royalty-free use under § 3178.5, or for prior approval of off-lease royalty-free use under § 3178.7:

- A complete description of the operation to be conducted, including the location of all facilities and equipment involved in the operation and the location of the FMP;
- The volume of oil or gas that the operator expects will be used in the operation and the method of measuring or estimating that volume;

- If the volume expected to be used will be estimated, the basis for the estimate (e.g., equipment manufacturer's published consumption or usage rates); and
- The proposed disposition of the oil or gas used (e.g., whether gas used would be consumed as fuel, vented through use of a gas-activated pneumatic controller, returned to the reservoir, or disposed by some other method).

B. The BLM requests the revision of the following information collection activities in accordance with this final rule:

1. Request for Extension of Royalty-Free Flaring During Initial Production Testing (43 CFR 3179.101)

A regulation in the 2016 rule, 43 CFR 3179.103, allows gas to be flared royalty free during initial production testing. The regulation lists specific volume and time limits for such testing. An operator may seek an extension of those limits on royalty-free flaring by submitting a Sundry Notice (Form 3160-5) to the BLM.

A regulation in this final rule, 43 CFR 3179.101, is similar to the 2016 rule in addressing the royalty-free treatment of gas volumes flared during initial production testing. 43 CFR 3179.101 in this final rule would provide that gas flared during the initial production test of each completed interval in a well is royalty free until one of the following occurs:

- The operator determines that it has obtained adequate reservoir information;
- 30 days have passed since the beginning of the production test, unless the BLM approves a longer test period; or
- The operator has flared 50 MMcf of gas.

Section 3179.101 of this final rule also provides that an operator may request a longer test period by submitting a Sundry Notice.

2. Request for Extension of Royalty-Free Flaring During Subsequent Well Testing (43 CFR 3179.102)

A regulation in the 2016 rule, 43 CFR 3179.104, allows gas to be flared royalty free for no more than 24 hours during well tests subsequent to the initial production test. That regulation allows an operator to seek authorization to flare royalty free for a longer period by submitting a Sundry Notice (Form 3160-5) to the BLM.

A regulation in this final rule, 43 CFR 3179.102, is substantively identical to 43 CFR 3179.104 in the 2016 rule. Accordingly, the BLM requests that the information collection activity at 43 CFR 3179.102 of this final rule replace the activity at 43 CFR 3179.104 of the 2016 rule.

3. Emergencies (43 CFR 3179.103)

A regulation in the 2016 rule, 43 CFR 3179.105, allows an operator to flare gas royalty free during a temporary, short-term, infrequent, and unavoidable emergency. A regulation in this final rule, at 43 CFR 3179.103, is almost identical to 43 CFR 3179.105 of the 2016 rule. The BLM thus requests that the information collection activity entitled, “Reporting of Venting or Flaring (43 CFR 3179.105)” be re-named “Emergencies (43 CFR 3179.103).”

As provided at 43 CFR 3179.103(a) of this final rule, gas flared or vented during an emergency would be royalty-free for a period not to exceed 24 hours, unless the BLM determines that emergency conditions exist necessitating venting or flaring for a longer period. Section 3179.103(d) of this final rule would require the operator to report to the

BLM on a Sundry Notice, within 45 days of the start of an emergency, the estimated volumes flared or vented beyond the timeframe specified in paragraph (a).

As defined at 43 CFR 3179.103(b) of this final rule, an “emergency” for purposes of 43 CFR subpart 3179 is a temporary, infrequent and unavoidable situation in which the loss of gas or oil is uncontrollable or necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment, and is not due to operator negligence.

As provided at 43 CFR 3179.103(c) of this final rule, the following events would not constitute emergencies for the purposes of royalty assessment:

- The operator's failure to install appropriate equipment of a sufficient capacity to accommodate the production conditions;
- Failure to limit production when the production rate exceeds the capacity of the related equipment, pipeline, or gas plant, or exceeds sales contract volumes of oil or gas;
- Scheduled maintenance;
- A situation caused by operator negligence, including recurring equipment failures; or
- A situation on a lease, unit, or communitized area that has already experienced 3 or more emergencies within the past 30 days, unless the BLM determines that the occurrence of more than 3 emergencies within the 30 day period could not have been anticipated and was beyond the operator's control.

D. The BLM requests the removal of the following information collection activities in accordance with this final rule:

1. “Plan to Minimize Waste of Natural Gas”;

2. “Notification of Choice to Comply on County- or State-wide Basis”;

3. “Request for Approval of Alternative Capture Requirement”;

4. “Request for Exemption from Well Completion Requirements”;

5. “Notification of Functional Needs for a Pneumatic Controller”;

6. “Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Controller)”;

7. “Showing in Support of Replacement of Pneumatic Controller within 3 Years”;

8. “Showing that a Pneumatic Diaphragm Pump was Operated on Fewer than 90 Individual Days in the Prior Calendar Year”;

9. “Notification of Functional Needs for a Pneumatic Diaphragm Pump”;

10. “Showing that Cost of Compliance Would Cause Cessation of Production and Abandonment of Oil Reserves (Pneumatic Diaphragm Pump)”;

11. “Showing in Support of Replacement of Pneumatic Diaphragm Pump within 3 Years”;

12. “Storage Vessels”;

13. “Downhole Well Maintenance and Liquids Unloading – Documentation and Reporting”;

14. “Downhole Well Maintenance and Liquids Unloading – Notification of Excessive Duration or Volume”;

15. “Leak Detection – Compliance with EPA Regulations”;

16. “Leak Detection – Request to Use an Alternative Monitoring Device and Protocol”;

17. “Leak Detection – Operator Request to Use an Alternative Leak Detection Program”;

18. “Leak Detection – Operator Request for Exemption Allowing Use of an Alternative Leak-Detection Program that Does Not Meet Specified Criteria”;

19. “Leak Detection – Notification of Delay in Repairing Leaks”;

20. “Leak Detection — Inspection Recordkeeping and Reporting”; and

21. “Leak Detection – Annual Reporting of Inspections.”

E. The BLM requests the addition of following information collection activity, in accordance with this final rule: Oil-Well Gas (43 CFR 3179.201)

A regulation in this final rule, 43 CFR 3179.201, would provide that, except as otherwise provided in 43 CFR subpart 3179, oil-well gas may not be vented or flared royalty free unless BLM approves such action in writing. The BLM would be authorized to approve an application for royalty-free venting or flaring of oil-well gas upon determining that royalty-free venting or flaring is justified by the operator's submission of either:

1) An evaluation report supported by engineering, geologic, and economic data that demonstrates to the BLM's satisfaction that the expenditures necessary to market or beneficially use such gas are not economically justified; or

2) An action plan showing how the operator will minimize the venting or flaring of the gas within 1 year or within a greater amount of time if the operator justifies an extended deadline. If the operator fails to implement the action plan, the gas vented or flared during the time covered by the action plan would be subject to royalty.

The data in the evaluation report that is mentioned above would need to include:

- The applicant's estimates of the volumes of oil and gas that would be produced to the economic limit if the application to vent or flare were approved; and
- The volumes of the oil and gas that would be produced if the applicant were required to market or use the gas.

The BLM would be authorized to require the operator to provide an updated evaluation report as additional development occurs or economic conditions improve. In

addition, the BLM would be authorized to determine that gas is avoidably lost and therefore subject to royalty if flaring exceeds 10 MMcf per well during any month.

The BLM notes that there are no additional reporting requirements associated with 43 CFR 3179.301 in the final rule. Section 3179.301, which is a revision of 43 CFR 3179.9, is already covered under an approved OMB control number 1012-0004. The provision provides that the operator must estimate or measure volumes of gas vented or flared, and report those volumes under "applicable ONRR reporting requirements," which is authorized under control number 1012-0004. An ONRR regulation (30 CFR 1210.102) requires operators to submit a form that is included in that control number (Form ONRR-4054, Oil and Gas Operations Report) monthly for all oil and gas production. Volumes of vented gas and flared gas must be included in that report, using codes to identify those volumes. ONRR uses the information on Form ONRR-4054 to track all oil and gas from the point of production to the point of first sale or other disposition, to ensure proper royalties are paid. The BLM and other Federal Government agencies use the data to monitor and inspect lease operations. As revised, proposed 43 CFR 3179.301 does not change the burdens that ONRR estimates for Form ONRR-4054.

4. Burden Estimates

This final rule results in the following adjustments in hour or cost burdens:

1. The hours per response for Request for Approval for Royalty-Free Uses On-Lease or Off-Lease are increased from 4 to 8.

2. The number of responses for "Request for Extension of Royalty-Free Flaring During Initial Well Testing" are increased from 500 to 750.

Program changes in this final rule would result in 62,125 fewer responses than in the 2016 rule (1,075 responses minus 63,200 responses) and 78,160 fewer burden hours than in the 2016 rule (4,010 responses minus 82,170 responses. The program changes and their reasons are itemized in Tables 15-1 and 15-2 of the supporting statement.

The following table details the annual estimated hour burdens for the information activities described above:

A. **Type of Response**	**B.** **Number of Responses**	**C.** **Hours per Response**	**D.** **Total Hours (Column B x Column C)**
Request for Approval for Royalty-Free Uses On-Lease or Off-Lease 43 CFR 3178.5, 3178.7, 3178.8, and 3178.9 Form 3160-5	50	8	400
Request for Extension of Royalty-Free Flaring During Initial Production Testing 43 CFR 3179.101 Form 3160-5	750	2	1,500
Request for Extension of Royalty-Free Flaring During Subsequent Well Testing 43 CFR 3179.102 Form 3160-5	5	2	10
Emergencies 43 CFR 3179.103 Form 3160-5	250	2	500
Oil-Well Gas 43 CFR 3179.201	20	80	1,600
Totals	1,075	—	4,010

National Environmental Policy Act

The BLM has prepared an Environmental Assessment (EA) to determine whether this proposed rule would have a significant impact on the quality of the human

environment under the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321 *et seq.*). Based on this EA, the BLM has concluded that the final rule would not have a significant impact on the quality of the human environment. This conclusion is detailed in the BLM's Finding of No Significant Impact (FONSI). Both the EA and the FONSI for the final rule are available in the docket for the rule on the *Federal eRulemaking Portal*: https://www.regulations.gov. (In the Searchbox, enter "RIN 1004-AE53", click the "Search" button, open the Docket Folder, and look under Supporting Documents.)

Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use (Executive Order 13211)

This final rule is not a significant energy action under the definition in Executive Order 13211. A statement of Energy Effects is not required.

Section 4(b) of Executive Order 13211 defines a "significant energy action" as "any action by an agency (normally published in the *Federal Register*) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of rulemaking, and notices of rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) Is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) That is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The rule rescinds or revises certain requirements in the 2016 rule and reduces compliance burdens. The BLM determined that the 2016 rule would not have impacted the supply, distribution, or use of energy. It stands to reason that a revision in a manner

that conforms 43 CFR subpart 3179 with the policies governing venting and flaring prior to the 2016 rule will likewise not have an impact on the supply, distribution, or use of energy. As such, we do not consider the final rule to be a "significant energy action" as defined in Executive Order 13211.

Authors

The principal authors of this final rule are: James Tichenor, Justin Abernathy, Michael Riches, and Nathan Packer of the BLM Washington Office; Adam Stern of the Department of the Interior's Office of Policy Analysis; Beth Poindexter of the BLM Montana and North Dakota State Office; David Mankiewicz of the BLM Farmington, New Mexico Field Office; and Jennifer Sanchez of the BLM Roswell, New Mexico Field Office; assisted by Faith Bremner of the BLM's Division of Regulatory Affairs and by the Department of the Interior's Office of the Solicitor.

List of Subjects

43 CFR Part 3160

Administrative practice and procedure; Government contracts; Indians-lands; Mineral royalties; Oil and gas exploration; Penalties; Public lands--mineral resources; Reporting and recordkeeping requirements.

43 CFR Part 3170

Administrative practice and procedure; Flaring; Government contracts; Incorporation by reference; Indians-lands; Mineral royalties; Immediate assessments; Oil and gas exploration; Oil and gas measurement; Public lands--mineral resources; Reporting and record keeping requirements; Royalty-free use; Venting.

Dated: ______________________________

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Joseph R. Balash,

Assistant Secretary for Land and Minerals Management

43 CFR Chapter II

For the reasons set out in the preamble, the Bureau of Land Management amends 43 CFR parts 3160 and 3170 as follows:

PART 3160 – ONSHORE OIL AND GAS OPERATIONS

1. The authority citation for part 3160 continues to read as follows:

AUTHORITY: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740; and Sec. 107, Pub. L. 114-74, 129 Stat. 599, unless otherwise noted.

§ 3162.3-1 [Amended]

2. Amend § 3162.3-1 by removing paragraph (j).

PART 3170 – ONSHORE OIL AND GAS PRODUCTION

3. The authority citation for part 3170 continues to read as follows:

AUTHORITY: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

4. Revise subpart 3179 to read as follows:

SUBPART 3179—WASTE PREVENTION AND RESOURCE CONSERVATION

SECS.

3179.1 Purpose.

3179.2 Scope.

3179.3 Definitions and acronyms.

3179.4 Determining when the loss of oil or gas is avoidable or unavoidable.

3179.5 When lost production is subject to royalty.

3179.6 Venting limitations.

AUTHORIZED FLARING AND VENTING OF GAS

OTHER VENTING OR FLARING

MEASUREMENT AND REPORTING RESPONSIBILITIES

ADDITIONAL DEFERENCE TO TRIBAL REGULATIONS

SUBPART 3179—WASTE PREVENTION AND RESOURCE CONSERVATION

§ 3179.1 Purpose.

The purpose of this subpart is to implement and carry out the purposes of statutes relating to prevention of waste from Federal and Indian (other than Osage Tribe) leases, conservation of surface resources, and management of the public lands for multiple use and sustained yield. This subpart supersedes those portions of Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost (NTL-4A), pertaining to, among other things, flaring and venting of produced gas, unavoidably and avoidably lost gas, and waste prevention.

§ 3179.2 Scope.

(a) This subpart applies to:

(1) All onshore Federal and Indian (other than Osage Tribe) oil and gas leases, units, and communitized areas, except as otherwise provided in this subpart;

(2) IMDA oil and gas agreements, unless specifically excluded in the agreement or unless the relevant provisions of this subpart are inconsistent with the agreement;

(3) Leases and other business agreements and contracts for the development of tribal energy resources under a Tribal Energy Resource Agreement entered into with the Secretary, unless specifically excluded in the lease, other business agreement, or Tribal Energy Resource Agreement;

(4) Committed State or private tracts in a federally approved unit or communitization agreement defined by or established under 43 CFR subpart 3105 or 43 CFR part 3180; and

(5) All onshore well facilities located on a Federal or Indian lease or a federally approved unit or communitized area.

(b) For purposes of this subpart, the term “lease” also includes IMDA agreements.

§ 3179.3 Definitions and acronyms.

As used in this subpart, the term:

Automatic ignition system means an automatic ignitor and, where needed to ensure continuous combustion, a continuous pilot flame.

Capture means the physical containment of natural gas for transportation to market or productive use of natural gas, and includes injection and royalty-free on-site uses pursuant to subpart 3178.

Gas-to-oil ratio (GOR) means the ratio of gas to oil in the production stream expressed in standard cubic feet of gas per barrel of oil.

Gas well means a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, exceeds the energy equivalent of the oil produced, as determined at the time of well completion.

Liquids unloading means the removal of an accumulation of liquid hydrocarbons or water from the wellbore of a completed gas well.

Lost oil or lost gas means produced oil or gas that escapes containment, either intentionally or unintentionally, or is flared before being removed from the lease, unit, or communitized area, and cannot be recovered.

Oil well means a well for which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced, as determined at the time of well completion.

Waste of oil or gas means any act or failure to act by the operator that is not sanctioned by the authorized officer as necessary for proper development and production, where compliance costs are not greater than the monetary value of the resources they are expected to conserve, and which results in: (1) A reduction in the quantity or quality of oil and gas ultimately producible from a reservoir under prudent and proper operations; or (2) avoidable surface loss of oil or gas.

§ 3179.4 Determining when the loss of oil or gas is avoidable or unavoidable.

For purposes of this subpart:

(a) *Avoidably lost* production means:

(1) Gas that is vented or flared without the authorization or approval of the BLM; or

(2) Produced oil or gas that is lost when the BLM determines that such loss occurred as a result of:

(i) Negligence on the part of the operator;

(ii) The failure of the operator to take all reasonable measures to prevent or control the loss; or

(iii) The failure of the operator to comply fully with the applicable lease terms and regulations, appropriate provisions of the approved operating plan, or prior written orders of the BLM.

(b) *Unavoidably lost* production means:

(1) Oil or gas that is lost because of line failures, equipment malfunctions, blowouts, fires, or other similar circumstances, except where the BLM determines that the loss was avoidable pursuant to § 3179.4(a)(2);

(2) Oil or gas that is lost from the following operations or sources, except where the BLM determines that the loss was avoidable pursuant to § 3179.4(a)(2):

(i) Well drilling;

(ii) Well completion and related operations;

(iii) Initial production tests, subject to the limitations in § 3179.101;

(iv) Subsequent well tests, subject to the limitations in § 3179.102;

(v) Exploratory coalbed methane well dewatering;

(vi) Emergencies, subject to the limitations in § 3179.103;

(vii) Normal gas vapor losses from a storage tank or other low pressure production vessel, unless the BLM determines that recovery of the gas vapors is warranted;

(viii) Well venting in the course of downhole well maintenance and/or liquids unloading performed in compliance with § 3179.104; or

(ix) Facility and pipeline maintenance, such as when an operator must blow-down and depressurize equipment to perform maintenance or repairs; or

(3) Produced gas that is flared or vented with BLM authorization or approval.

§ 3179.5 When lost production is subject to royalty.

(a) Royalty is due on all avoidably lost oil or gas.

(b) Royalty is not due on any unavoidably lost oil or gas.

§ 3179.6 Venting limitations.

(a) Gas well gas may not be flared or vented, except where it is unavoidably lost pursuant to § 3179.4(b).

(b) The operator must flare, rather than vent, any gas that is not captured, except:

(1) When flaring the gas is technically infeasible, such as when the gas is not readily combustible or the volumes are too small to flare;

(2) Under emergency conditions, as defined in § 3179.105, when the loss of gas is uncontrollable or venting is necessary for safety;

(3) When the gas is vented through normal operation of a natural gas-activated pneumatic controller or pump;

(4) When gas vapor is vented from a storage tank or other low pressure production vessel, unless the BLM determines that recovery of the gas vapors is warranted;

(5) When the gas is vented during downhole well maintenance or liquids unloading activities;

(6) When the gas venting is necessary to allow non-routine facility and pipeline maintenance to be performed, such as when an operator must, upon occasion, blow-down and depressurize equipment to perform maintenance or repairs; or

(7) When a release of gas is unavoidable under § 3179.4 and flaring is prohibited by Federal, State, local or tribal law, regulation, or enforceable permit term.

(c) For purposes of this subpart, all flares or combustion devices must be equipped with an automatic ignition system.

AUTHORIZED FLARING AND VENTING OF GAS

§ 3179.101 Initial production testing.

(a) Gas flared during the initial production test of each completed interval in a well is royalty free until one of the following occurs:

(1) The operator determines that it has obtained adequate reservoir information;

(2) 30 days have passed since the beginning of the production test, unless the BLM approves a longer test period; or

(3) The operator has flared 50 million cubic feet (MMcf) of gas.

(b) The operator may request a longer test period and must submit its request using a Sundry Notice.

§ 3179.102 Subsequent well tests.

(a) Gas flared during well tests subsequent to the initial production test is royalty free for a period not to exceed 24 hours, unless the BLM approves or requires a longer test period.

(b) The operator may request a longer test period and must submit its request using a Sundry Notice.

§ 3179.103 Emergencies.

(a) Gas flared or vented during an emergency is royalty free for a period not to exceed 24 hours, unless the BLM determines that emergency conditions exist necessitating venting or flaring for a longer period.

(b) For purposes of this subpart, an “emergency” is a temporary, infrequent and unavoidable situation in which the loss of gas or oil is uncontrollable or necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment, and is not due to operator negligence.

(c) The following do not constitute emergencies for the purpose of royalty assessment:

(1) The operator’s failure to install appropriate equipment of a sufficient capacity to accommodate the production conditions;

(2) Failure to limit production when the production rate exceeds the capacity of the related equipment, pipeline, or gas plant, or exceeds sales contract volumes of oil or gas;

(3) Scheduled maintenance;

(4) A situation caused by operator negligence, including recurring equipment failures; or

(5) A situation on a lease, unit, or communitized area that has already experienced 3 or more emergencies within the past 30 days, unless the BLM determines that the occurrence of more than 3 emergencies within the 30 day period could not have been anticipated and was beyond the operator's control.

(d) Within 45 days of the start of the emergency, the operator must estimate and report to the BLM on a Sundry Notice the volumes flared or vented beyond the timeframe specified in paragraph (a) of this section.

§ 3179.104 Downhole well maintenance and liquids unloading.

(a) Gas vented or flared during downhole well maintenance and well purging is royalty free for a period not to exceed 24 hours per event, provided that the requirements of paragraphs (b) through (d) of this section are met. Gas vented or flared from a plunger lift system and/or an automated well control system is royalty free, provided the requirements of paragraphs (b) and (c) of this section are met.

(b) The operator must minimize the loss of gas associated with downhole well maintenance and liquids unloading, consistent with safe operations.

(c) For wells equipped with a plunger lift system and/or an automated well control system, minimizing gas loss under paragraph (b) of this section includes optimizing the operation of the system to minimize gas losses to the extent possible consistent with removing liquids that would inhibit proper function of the well.

(d) For any liquids unloading by manual well purging, the operator must ensure that the person conducting the well purging remains present on-site throughout the event to end the event as soon as practical, thereby minimizing to the maximum extent practicable any venting to the atmosphere;

(e) For purposes of this section, "well purging" means blowing accumulated liquids out of a wellbore by reservoir gas pressure, whether manually or by an automatic control system that relies on real-time pressure or flow, timers, or other well data, where the gas

is vented to the atmosphere, and it does not apply to wells equipped with a plunger lift system.

OTHER VENTING OR FLARING

§ 3179.201 Oil-well gas.

(a) Except as provided in §§ 3179.101, 3179.102, 3179.103, and 3179.104 of this subpart, vented or flared oil-well gas is royalty free if it is vented or flared pursuant to applicable rules, regulations, or orders of the appropriate State regulatory agency or tribe. Applicable State or tribal rules, regulations, or orders are appropriate if they place limitations on the venting and flaring of oil-well gas, including through general or qualified prohibitions, volume or time limitations, capture percentage requirements, or trading mechanisms.

(b) With respect to production from Indian leases, vented or flared oil-well gas will be treated as royalty free pursuant to paragraph (a) of this section only to the extent it is consistent with the BLM's trust responsibility.

(c) Except as otherwise provided in this subpart, oil-well gas may not be vented or flared royalty free unless the BLM approves it in writing. The BLM may approve an application for royalty-free venting or flaring of oil-well gas if it determines that it is justified by the operator's submission of either:

(1) An evaluation report supported by engineering, geologic, and economic data that demonstrates to the BLM's satisfaction that the expenditures necessary to market or beneficially use such gas are not economically justified. If flaring exceeds 10 MMcf per well during any month, the BLM may determine that the gas is avoidably lost and therefore subject to royalty; or

(2) An action plan showing how the operator will minimize the venting or flaring of the oil-well gas within 1 year. An operator may apply for approval of an extension of the 1-year time limit, if justified. If the operator fails to implement the action plan, the gas vented or flared during the time covered by the action plan will be subject to royalty. If flaring exceeds 10 MMcf per well during any month, the BLM may determine that the gas is avoidably lost and therefore subject to royalty.

(d) The evaluation report in paragraph (c)(1) of this section:

(1) Must include all appropriate engineering, geologic, and economic data to support the applicant's determination that marketing or using the gas is not economically viable. The information provided must include the applicant's estimates of the volumes of oil and gas that would be produced to the economic limit if the application to vent or flare were approved and the volumes of the oil and gas that would be produced if the applicant was required to market or use the gas. When evaluating the feasibility of marketing or using of the gas, the BLM will determine whether the operator can economically operate the lease if it is required to market or use the gas, considering the total leasehold production, including both oil and gas, as well as the economics of a field-wide plan; and

(2) The BLM may require the operator to provide an updated evaluation report as additional development occurs or economic conditions improve, but no more than once a year.

(e) An approval to flare royalty free, which is in effect as of the effective date of this rule, will continue in effect unless:

(1) The approval is no longer necessary because the venting or flaring is authorized by the applicable rules, regulations, or orders of an appropriate State regulatory agency or tribe, as provided in paragraph (a) of this section; or

(2) The BLM requires an updated evaluation report under paragraph (d)(2) of this section and determines to amend or revoke its approval.

MEASUREMENT AND REPORTING RESPONSIBILITIES

§ 3179.301 Measuring and reporting volumes of gas vented and flared.

(a) The operator must estimate or measure all volumes of lost oil and gas, whether avoidably or unavoidably lost, from wells, facilities and equipment on a lease, unit PA, or communitized area and report those volumes under applicable ONRR reporting requirements.

(b) The operator may:

(1) Estimate or measure vented or flared gas in accordance with applicable rules, regulations, or orders of the appropriate State or tribal regulatory agency;

(2) Estimate the volume of the vented or flared gas based on the results of a regularly performed GOR test and measured values for the volumes of oil production and gas sales, to allow BLM to independently verify the volume, rate, and heating value of the flared gas; or

(3) Measure the volume of the flared gas.

(c) The BLM may require the installation of additional measurement equipment whenever it is determined that the existing methods are inadequate to meet the purposes of this subpart.

(d) The operator may combine gas from multiple leases, unit PAs, or communitized areas for the purpose of flaring or venting at a common point, but must use a method approved by the BLM to allocate the quantities of the vented or flared gas to each lease, unit PA, or communitized area.

ADDITIONAL DEFERENCE TO TRIBAL REGULATIONS

§ 3179.401 Deference to tribal regulations.

(a) A tribe that has rules, regulations, or orders that are applicable to any of the matters addressed in subpart 3179 may seek approval from the BLM to have such rules, regulations, or orders apply in place of any or all of the provisions of subpart 3179 with respect to lands and minerals over which that tribe has jurisdiction.

(b) The BLM will approve a tribe's request under paragraph (a) to the extent that it is consistent with the BLM's trust responsibility.

(c) The deference to tribal rules, regulations, or orders provided for in this section is supplemental to, and does not limit, the deference to tribal rules, regulations, or orders provided for in § 3179.201.

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UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF CALIFORNIA

SIERRA CLUB; LOS PADRES FORESTWATCH; CENTER FOR BIOLOGICAL DIVERSITY; EARTHWORKS; ENVIRONMENTAL DEFENSE FUND; NATURAL RESOURCES DEFENSE COUNCIL; THE WILDERNESS SOCIETY; NATIONAL WILDLIFE FEDERATION; CITIZENS FOR A HEALTHY COMMUNITY; DINÉ CITIZENS AGAINST RUINING OUR ENVIRONMENT; ENVIRONMENTAL LAW AND POLICY CENTER; FORT BERTHOLD PROTECTORS OF WATER AND EARTH RIGHTS; MONTANA ENVIRONMENTAL INFORMATION CENTER; SAN JUAN CITIZENS ALLIANCE; WESTERN ORGANIZATION OF RESOURCE COUNCILS; WILDERNESS WORKSHOP; WILDEARTH GUARDIANS; and WYOMING OUTDOOR COUNCIL, Plaintiffs, v. RYAN ZINKE, in his official capacity as Secretary of the Interior; BUREAU OF LAND MANAGEMENT; and UNITED STATES DEPARTMENT OF THE INTERIOR, Defendants.	Case No. 3:18-cv-5984 **COMPLAINT FOR DECLARATORY AND INJUNCTIVE RELIEF** (Administrative Procedure Act, 5 U.S.C. § 551, *et seq.*)

INTRODUCTION

1. This case challenges the U.S. Bureau of Land Management's (BLM) final rule, 83 Fed. Reg. 49,184 (Sept. 28, 2018) (Rescission Rule), rescinding almost all provisions of the Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule, 81 Fed. Reg. 83,008 (Nov. 18, 2016) (Waste Prevention Rule). The Rescission Rule unlawfully revokes reasonable protections designed to limit waste of natural gas by oil and gas companies on federal public and Indian lands resulting from venting, flaring (burning gas without capturing its energy), and equipment leaks.

2. In 2016, BLM adopted the Waste Prevention Rule in response to numerous reports by other federal agencies and its own findings identifying rampant waste of publicly and tribally owned natural gas. BLM determined that its existing waste-prevention regulation, Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL-4A), 44 Fed. Reg. 76,600 (Dec. 27, 1979), was inadequate to prevent waste of publicly owned resources, and that further precautions were reasonable and necessary.

3. To fulfill Congress's mandate that BLM must require lessees to use "all reasonable precautions to prevent waste," 30 U.S.C. § 225, the Waste Prevention Rule required operators to control venting, flaring, and leaks and bring more gas to market using proven, widely-available technologies that some (but not all) states already require, and that many companies already use voluntarily.

4. In addition to reducing waste, the Waste Prevention Rule had many other benefits. Because oil and gas companies must pay royalties on captured gas, the Rule would have resulted in millions of dollars of increased royalty payments that states, tribes, and local governments could have used to fund schools, healthcare, and infrastructure. The Waste Prevention Rule also reduced air and climate pollution that results when natural gas is leaked or vented into the air or burned in flares.

5. The Waste Prevention Rule became effective on January 17, 2017.

6. Shortly thereafter, President Trump and Defendant Secretary of the Interior Ryan Zinke directed BLM to reconsider the Waste Prevention Rule in Executive Order 13,738 and Secretarial Order 3349, respectively.

7. On September 18, 2018, Secretary Zinke's BLM finalized the Rescission Rule. The Rescission Rule was published in the Federal Register on September 28, 2018. The Rescission Rule removes almost all of the Waste Prevention Rule requirements that "generate benefits of gas savings or reductions in methane emissions." 83 Fed. Reg. at 49,204.

8. BLM justifies its decision to rescind these reasonable waste prevention measures by adding a new definition of "waste of oil and gas." Pursuant to the new definition, the agency now considers only the profits of individual oil and gas companies—not economic losses or other impacts to the public—when deciding what constitutes waste. This definition violates the plain language and intent of the Mineral Leasing Act, which requires BLM to consider not just private oil and gas interests, but also the "interests of the United States" and the "public welfare" when regulating waste of publicly owned oil and gas resources leased, in the public interest, to oil and gas companies. 30 U.S.C. § 187. Indeed, BLM ignores altogether its legal obligations to protect the public and the environment under the Mineral Leasing Act and the, 43 U.S.C. §§ 1701(a)(8), 1732(b).

9. Further, BLM fails to justify rescinding the Waste Prevention Rule without following the legally required procedure under the Administrative Procedure Act (APA), including (1) demonstrating that the new approach is permissible under the governing statutes, (2) showing there are "good reasons" for changing the rule, and (3) offering a "reasoned explanation" for its changed position. *Fed. Commc'ns Comm'n v. Fox Television Stations, Inc.*, 556 U.S. 502, 514–16 (2009). BLM offers numerous justifications for the Rescission Rule that conflict with its prior conclusions and supporting evidence, but BLM fails to support these new positions.

10. For example, BLM attempts to justify the Rescission Rule by claiming that the Waste Prevention Rule would have unnecessarily burdened energy production, constrained economic growth, and prevented job creation. In fact, BLM's own evidence shows that the Rescission Rule will lead to a *decrease* in natural gas production of 299 billion cubic feet (bcf). BLM analyzed the economic impact of the Rescission Rule on small businesses and estimates that the per-entity

reduction in compliance costs would result in an average increase in profit margin of only 0.19%, an amount that is unlikely to constrain economic growth or prevent job creation. BLM admits that the Rescission Rule will not affect the price, supply or distribution of energy, will not alter investment and employment decisions, and will not have a significant effect on a substantial number of small entities.

11. BLM also attempts to justify the Rescission Rule based on a reassessment of costs and benefits that arbitrarily understates the Waste Prevention Rule's benefits and overstates its costs. For example, BLM relies on an "interim" value for the social cost of methane—a measure of the economic harm to society resulting from climate change—that cuts the Rule's projected benefits by 96% or 87%, depending on the discount rate used. BLM does so by excluding significant domestic and global impacts.

12. BLM also violates our country's environmental Magna Carta, the National Environmental Policy Act (NEPA). BLM relies on a cursory 26-page Environmental Assessment (EA) rather than a more comprehensive Environmental Impact Statement (EIS) despite the Rescission Rule's significant environmental impacts. The EA fails to acknowledge, let alone take a hard look at, the consequences to people and communities of the agency's decision to repeal a nationwide regulation and instead to rely on a patchwork of different state and tribal regulations. This failure is particularly acute relative to areas that are already violating federal air quality standards and in tribal communities that are already suffering from increased health risks as well as noise and light pollution and other environmental justice impacts caused by oil and gas development. BLM also fails to consider the cumulative impacts of the Rescission Rule in combination with any other past, present, or reasonably foreseeable actions—in particular the cumulative climate impact of the Rescission Rule in combination with the federal public and tribal lands oil and gas program as a whole.

13. Despite its failure to consider these environmental impacts, BLM makes the unsupported conclusion in its Finding of No Significant Impact (FONSI) that rescinding the protective provisions of the Waste Prevention Rule nationwide "will not have a significant effect on the quality of the human environment, individually or cumulatively with other actions" and therefore

an EIS is not required. In fact, extensive record evidence shows that the Rescission Rule will have significant negative public health and climate impacts, and there is a high degree of controversy and uncertainty surrounding the use of the social cost of methane. For these and other reasons, BLM must prepare an EIS.

14. Plaintiffs Sierra Club, *et al.* (Conservation and Tribal Citizen Groups) challenge the Rescission Rule based on violations of the Mineral Leasing Act, 30 U.S.C. §§ 187, 225; Federal Land Policy Management Act (FLPMA), 43 U.S.C. §§ 1701(a)(8), 1702(c), 1732(b); NEPA, 42 U.S.C. § 4332(C); and the APA, 5 U.S.C. §§ 553, 706(2)(A), (C).

15. The Conservation and Tribal Citizen Groups respectfully seek a declaration that the Rescission Rule violates the Mineral Leasing Act, FLPMA, NEPA, and the APA, and is arbitrary, capricious, contrary to law, and in excess of authority within the meaning of 5 U.S.C. §§ 706(2)(A), (C). The Conservation and Tribal Citizen Groups also seek an order vacating the Rescission Rule and immediately reinstating all provisions of the Waste Prevention Rule.

JURISDICTION AND VENUE

16. This Court has jurisdiction pursuant to 28 U.S.C. § 1331 (federal question jurisdiction) and 5 U.S.C. § 702 (the APA).

17. An actual controversy exists between the parties within the meaning of 28 U.S.C. § 2201(a). This Court may grant declaratory relief, injunctive relief, and other relief pursuant to 28 U.S.C. §§ 2201–2202 and 5 U.S.C. §§ 705–706.

18. Venue is proper in this Court pursuant to 28 U.S.C. § 1391(e)(1) because Plaintiffs reside in this district. Plaintiffs Sierra Club, Center for Biological Diversity, and Los Padres Forest Watch are all nonprofit corporations in good standing incorporated in the State of California. Plaintiff Sierra Club is headquartered in Oakland, and Center for Biological Diversity and Earthworks have offices in Oakland. Additionally, Plaintiffs Environmental Defense Fund, Natural Resources Defense Council, and The Wilderness Society maintain offices in this district. The Conservation and Tribal Citizen Groups collectively have more than 500,000 members living in California. This includes more than 160,000 members residing in the Northern District.

19. Additionally, a substantial part of the events giving rise to this complaint occurred in this district because BLM specifically manages public oil and gas resources in this district that are subject to the Waste Prevention Rule. BLM administers 15.2 million acres of public lands, 47 million acres of subsurface mineral estate, and 592,000 acres of Native American tribal mineral estate in California. At the end of fiscal year 2016, BLM administered 530 oil and gas leases in California, covering 198,820 acres and containing around 6,854 producing wells. In 2016, California operators developed more than 11 million barrels of federal oil and 12 bcf of federal natural gas, and flared more than 0.4 bcf of federal natural gas.

INTRADISTRICT ASSIGNMENT

20. Pursuant to Civil Local Rules 3-5(b) and 3-2(c), there is no basis for assignment of this action to any particular location or division of this Court. However, Case No. 4:18-cv-05712-DMR, filed by the States of California and New Mexico, also challenges the Rescission Rule. The legal claims in Case No. 4:18-cv-05712-DMR are nearly identical to the legal claims in this case. Pursuant to Fed. R. Civ. P. 42 and Civil Local Rule 3-12(b), Plaintiffs intend to promptly file a motion to consolidate and/or relate the cases.

PARTIES

21. Plaintiff SIERRA CLUB, founded in 1892, is the nation's oldest and largest grassroots environmental organization. Sierra Club is incorporated and headquartered in California, with a principal place of business at 2101 Webster St., Suite 1300, Oakland, CA 94612. Sierra Club has about 400 employees who work in California, including about 200 employees who work at its headquarters in Oakland. Sierra Club has thirteen local chapters in California, including five chapters in northern California that collectively have about 93,000 members: the Loma Prieta, Mother Lode, Redwood, San Francisco Bay, and Ventana Chapters. Sierra Club currently has more than 784,000 members nationwide, including more than 172,000 in California. More than 55,200 of these members reside in the Northern District of California. Sierra Club's mission is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. In

addition to helping people from all backgrounds explore nature and our outdoor heritage, Sierra Club works to promote clean energy, safeguard the health of communities, protect wildlife, and preserve our remaining wild places through grassroots activism, public education, lobbying, and legal action. Sierra Club pursues these objectives nationwide, including in California, by working to protect communities and lands administered by BLM from the harmful impacts of oil and gas development, including air and climate pollution from venting, leaking, and flaring in the oil and gas sector.

22. Plaintiff LOS PADRES FORESTWATCH is a community-supported nonprofit organization working to protect the Los Padres National Forest and other public lands along California's central coast from Monterey County to Los Angeles County. Its members and supporters – which number more than 500 in Monterey County and more than 13,000 throughout the Central Coast – are concerned about the environmental impacts of oil drilling on wildlife habitat, air and water quality, scenic views, and outdoor recreation in and around the Los Padres National Forest. The goal of ForestWatch's oil accountability program is to ensure that any existing and proposed oil drilling operations near the Los Padres National Forest are conducted responsibly and in a way that reduces or avoids environmental impacts to the fullest extent possible. Flaring, venting, and methane leaks occur in the Sespe Oil Field, the South Cuyama Oil Field, and the Russell Ranch Oil Field in Ventura, Santa Barbara, and San Luis Obispo counties; they also occur in scattered locations on BLM-administered lands in Monterey County. For the last fourteen years, ForestWatch has worked to monitor existing and proposed oil wells in these areas to ensure compliance with environmental laws and regulations.

23. Plaintiff CENTER FOR BIOLOGICAL DIVERSITY (the Center) is a nonprofit organization incorporated in the State of California that works through science, law, and policy to secure a future for all species, great or small, hovering on the brink of extinction. The Center has offices throughout the country, including an office in Oakland, California. The Center has over 63,000 members, including more than 14,400 in California. Specifically, the Center has more than 4,000 members residing in the Northern District of California. Although the Center pursues its objectives of protecting threatened and endangered species and their habitats nationwide, the Center specifically works to protect public lands administered by BLM in the Northern District of

California from the harmful impacts of oil and gas development, including methane emissions. The Center researches, documents, and raises awareness of the environmental consequences of oil and gas development and hydraulic fracturing in California. This campaign includes, among other efforts, publishing reports on aquifer contamination and seismic risks from oil and gas activities, rallying local governments, including Monterey County, to prohibit hydraulic fracturing, and litigating BLM's oil and gas leasing activities on California public lands.

24. Plaintiff EARTHWORKS is a membership-based 501(c)(3) nonprofit organization dedicated to protecting communities and the environment from the adverse impacts of mineral and energy development while promoting sustainable solutions. Earthworks was created in 2005, when two organizations (the Mineral Policy Center and the Oil & Gas Accountability Project) joined forces. Earthworks collaborates with communities and grassroots groups to reform government policies to better protect air, water, public lands and communities from threats posed by mineral development. Earthworks has an office in Oakland, where its Executive Director is based. Earthworks has more than 70,000 members nationwide, including over 9,200 members in California. Among Earthworks' members, approximately 4,200 live in the Northern District of California.

25. Plaintiff ENVIRONMENTAL DEFENSE FUND (EDF) is a national nonprofit organization representing over 450,000 members nationwide, including over 74,000 in California. Over 29,000 of these members reside in the Northern District of California. Since 1967, EDF has linked science, economics, and law to create innovative, equitable, and cost-effective solutions to urgent environmental problems. EDF employs more than 170 scientists, economists, engineers, business school graduates, and lawyers to help solve challenging environmental problems in a scientifically sound and cost-effective way. These staff work throughout the nation, including in two California offices, one in San Francisco, and one in Sacramento. More than 90 EDF staff members live and work in California. EDF pursues initiatives at the state and national levels designed to protect human health and the environment. Among these initiatives, EDF has worked to reduce waste from oil and gas operations on public lands along with its associated health-harming and climate-altering air pollution.

26. Plaintiff NATURAL RESOURCES DEFENSE COUNCIL (NRDC) is a non-profit environmental membership organization that uses law, science, and the support of more than 384,000 members throughout the United States, including nearly 67,000 in California, to protect wildlife and wild places and to ensure a safe and healthy environment for all living things. More than 28,000 NRDC's members reside in the Northern District of California. NRDC has offices throughout the country, including offices in San Francisco and Santa Monica, California. NRDC has a long-established history of working to protect public lands and clean air. In particular, NRDC has worked for decades to protect public lands, nearby communities, wildlife habitat and air quality from the threats posed by oil and gas development.

27. Plaintiff THE WILDERNESS SOCIETY (TWS) has a mission to protect wilderness and inspire Americans to care for our wild places. TWS has offices throughout the country, including offices in San Francisco and Pasadena, California, and a California Desert representative. TWS has more than 1,000,000 members and supporters around the West, including more than 91,000 in California. TWS has a long-standing interest in the management of public lands across the nation, and engages frequently in land use planning and project proposals that could potentially affect wilderness quality lands, wildlife habitat, and other natural resources, as well as the health, safety and quality of life of surrounding communities. TWS also has a long-standing interest in the use of our public and tribal lands for energy development, including supporting a transition to renewable energy, and ensuring that oil and gas and other energy development are focused in suitable locations and completed in a manner that does not harm other values. TWS has been actively involved in planning, policy, and conservation efforts in California, including the Northwest California Integrated Resource Management Plan for BLM lands in Humboldt, Mendocino, Del Norte, Trinity, Shasta, Siskiyou, Butte, and Tehama Counties. TWS also focuses on protecting the Cascade-Siskiyou National Monument, the San Gabriel Mountains, Sierra Nevada, the California Desert, and the Central Coast.

28. Plaintiff NATIONAL WILDLIFE FEDERATION (NWF), founded in 1936, is one of the nation's premier grassroots non-profit conservation advocacy and education organizations. The group is America's largest conservation organization with a mission to ensure that wildlife thrive in

a rapidly changing world. Headquartered in Reston, Virginia, NWF has offices throughout the country, including an office in California. NWF has more than six million members and supporters and has affiliate organizations in 53 states and territories, including more than 59,000 members and 2,800 affiliate members in California. Over 20,700 of NWF's members reside in the Northern District of California. NWF has a strong history of protecting public lands for wildlife and outdoor recreation by its members and works to combine strong science, federal and state policy development, education, litigation, and grassroots organizing.

29. Plaintiff CITIZENS FOR A HEALTHY COMMUNITY (CHC) is a grass-roots organization with more than 500 members formed in 2009 for the purpose of protecting people and their environment from the impacts of BLM-authorized oil and gas development in the Delta County region of Colorado. CHC's members and supporters include organic farmers, ranchers, vineyard and winery owners, sportsmen, realtors, and other concerned citizens impacted by oil and gas development. CHC members have been actively involved in commenting on BLM's oil and gas activities.

30. Plaintiff DINÉ CITIZENS AGAINST RUINING OUR ENVIRONMENT (Diné C.A.R.E.) is an all-Navajo organization comprised of a federation of grassroots community activists in Arizona, New Mexico and Utah who strive to educate and advocate for traditional teachings derived from Diné Fundamental Laws. Diné C.A.R.E.'s goal is to protect all life in their ancestral homeland by empowering local and traditional people to organize, speak out, and determine the outlook of the environment through civic involvement and engagement in decision-making processes relating to tribal development, including oil and gas development on public and tribal lands in the San Juan Basin of New Mexico.

31. Plaintiff ENVIRONMENTAL LAW AND POLICY CENTER (ELPC) is a Midwest based not-for-profit corporation and legal advocacy organization concerned with improving environmental quality and protecting natural resources in the Midwest and Great Plains states. ELPC works on a variety of issues throughout the Midwest and Great Plains states, including advocating for clean air, clean water, renewable energy, sustainable transportation, and protecting natural places. ELPC's work includes efforts to minimize negative environmental impacts from oil

and gas development. ELPC has members in North Dakota whose recreational and aesthetic interests are impacted by the wasteful and polluting practices of venting and flaring natural gas from oil wells.

32. Plaintiff FORT BERTHOLD PROTECTORS OF WATER AND EARTH RIGHTS (Fort Berthold POWER) is a grassroots, member-led community group that works to promote responsible energy development in and around Fort Berthold Indian Reservation in North Dakota. Fort Berthold POWER is committed to working toward a sustainable society with an awareness for all life. The mission of Fort Berthold POWER is to conserve and protect the land, water, and air on which all life depends. Fort Berthold POWER works to engage citizens in activities that protect the environment, facilitates learning for members to disseminate information on environmental issues that affect all people, and expands members' ability to take effective action to address issues that affect land, air, and water.

33. Plaintiff MONTANA ENVIRONMENTAL INFORMATION CENTER (MEIC) is a nonprofit organization founded in 1973 with approximately 5,000 members and supporters throughout the United States, including in California. MEIC is dedicated to the preservation and enhancement of the natural resources and natural environment of Montana and to the gathering and disseminating of information concerning the protection and preservation of the human environment through education of its members and the general public concerning their rights and obligations under local, state, and federal environmental protection laws and regulations. MEIC is also dedicated to assuring that federal officials comply with and fully uphold the laws of the United States that are designed to protect the environment from pollution.

34. Plaintiff SAN JUAN CITIZENS ALLIANCE (SJCA), founded in 1986, organizes people to protect the water, air, lands, and the character of rural communities in the San Juan Basin. SJCA focuses on four program areas, one of which is the San Juan Basin Energy Reform Campaign, which seeks to ensure proper regulation and enforcement of the oil, gas, and coal industry and facilitate a transition to a renewable energy economy. SJCA has been active in BLM oil and gas issues in the San Juan Basin since the early 1990s. SJCA has 1000 members.

35. Plaintiff WESTERN ORGANIZATION OF RESOURCE COUNCILS (WORC) is a nonprofit organization that works to advance the vision of a democratic, sustainable, and just society through community action. WORC is committed to building sustainable environmental and economic communities that balance economic growth with the health of people and stewardship of their land, water, and air resources. WORC is a network of grassroots organizations from seven states that includes approximately 15,200 members and 39 local community group chapters. WORC's members are family farmers and ranchers, townspeople, and rural residents concerned about their communities and environment. WORC's current goals include organizing and educating landowners, residents, mineral estate owners and water users about the impacts of oil and gas exploration and development and ensuring that the BLM enforces all applicable laws and regulations related to oil and gas leasing and development.

36. Plaintiff WILDERNESS WORKSHOP is a nonprofit organization based in Carbondale, Colorado that is dedicated to preservation and conservation of the wilderness and natural resources of the White River National Forest and adjacent public lands. Wilderness Workshop engages in research, education, legal advocacy and grassroots organizing to protect the ecological integrity of local landscapes and public lands. Wilderness Workshop focuses on the monitoring and conservation of air and water quality, wildlife species and habitat, natural communities and lands of wilderness quality. Wilderness Workshop was founded in 1967 and has approximately 800 members.

37. Plaintiff WILDEARTH GUARDIANS (Guardians) is a non-profit conservation organization dedicated to protecting and restoring the wildlife, wild places, wild rivers, and health of the American West. Guardians has offices in Colorado, Montana, New Mexico, Arizona, Washington, and Oregon. With more than 120,000 members and supporters, Guardians works to sustain a transition from fossil fuels to clean energy in order to safeguard the West.

38. Plaintiff WYOMING OUTDOOR COUNCIL (WOC) was founded in 1967. It is Wyoming's oldest independent conservation organization. WOC works to protect Wyoming's environment and quality of life for future generations. Its goal is to develop productive and lasting solutions for managing natural resources through collaborative engagement with stakeholders and

decision makers. WOC believes responsible environmental stewardship is fundamental to safeguarding public health and Wyoming's quality of life. WOC's nearly 2,000 members recognize that Wyoming's landscapes, wildlife, and diverse cultural history are vital resources, and that everyone relies on the state's clean air and water.

39. The Conservation and Tribal Citizen Groups bring this action on behalf of themselves and their adversely affected members. For many years, the Conservation and Tribal Citizen Groups have actively advocated for strong BLM standards for the reduction of waste and associated air pollution from federal and tribal leases, and have devoted significant resources toward that effort. For example, the Conservation and Tribal Citizen Groups and their members submitted scoping comments and comments on the proposed Waste Prevention Rule and participated in public meetings and hearings. The Conservation and Tribal Citizen Groups also have intervened to defend the Waste Prevention Rule from a lawsuit filed by several states and industry groups. Further, the Conservation and Tribal Citizen Groups' staff and members helped to successfully oppose an attempt to persuade Congress to repeal the Rule using the Congressional Review Act. Moreover, the Conservation and Tribal Citizen Groups successfully sued BLM on two separate occasions when it unlawfully attempted to first stay, and then suspend, the Waste Prevention Rule's compliance dates. *California v. BLM*, 286 F. Supp. 3d 1054 (N.D. Cal. 2018) (*California II*); *California v. BLM*, Nos. 17-cv-3804-EDL & 17-cv-3885-EDL, 2017 WL 4416409, at *14 (Oct. 4, 2017) (*California I*). Finally, the Conservation and Tribal Citizen Groups and their members submitted comments on BLM's proposed Rescission Rule.

40. Many Conservation and Tribal Citizen Group members live in communities that receive income from royalties from oil and gas development on public and tribal lands that is used to fund schools, healthcare, and infrastructure. Other Conservation and Tribal Citizen Group members are partial royalty owners of tribal leases. The Rescission Rule will reduce these royalty payments.

41. Numerous Conservation and Tribal Citizen Group members live, work, and recreate in and around, and otherwise use and enjoy, lands where oil and gas development is occurring or has been proposed on federal and tribal leases and are therefore likely to be affected by the associated air pollution and other impacts from such development. For example, some members live on or near

split estate lands (where the federal government owns the minerals underlying their property) that are already subject to oil and gas development or are likely to be developed in the future. Other members use public lands in and around federal and tribal leases for recreation, wildlife viewing, solitude, and scientific study. The Rescission Rule will adversely affect these members. As a result of BLM rescinding almost all provisions of the Waste Prevention Rule that reduce waste, operators will be permitted to release more air pollution and flare more gas—which causes bright, incandescent fires at flare stacks and excessive noise. This harms the Conservation and Tribal Citizen Groups' members by disrupting their daily lives, subjecting them to adverse health risks, and reducing their enjoyment of the public, split estate, and tribal lands where they live and recreate.

42. Defendant RYAN ZINKE is the Secretary of the Interior. The Conservation and Tribal Citizen Groups sue Secretary Zinke in his official capacity. Secretary Zinke oversees the development of energy, including natural resource extraction, on federal and tribal leases. Secretary Zinke is ultimately responsible for BLM's Rescission Rule.

43. Defendant BUREAU OF LAND MANAGEMENT is an agency of the United States within the Department of the Interior. BLM is responsible for managing publicly owned lands and minerals, in accordance with federal law. BLM promulgated the Waste Prevention Rule, and later promulgated the Rescission Rule.

44. Defendant U.S. DEPARTMENT OF THE INTERIOR is an executive branch department that oversees BLM, and is thus ultimately responsible for BLM's Rescission Rule.

BACKGROUND

I. BLM Adopted the Waste Prevention Rule in 2016 to Ensure Operators Take "All Reasonable Precautions" Against the Rampant Waste of Public Resources as Required by the Mineral Leasing Act.

45. BLM developed the Waste Prevention Rule to fulfill its obligation under the Mineral Leasing Act to ensure that when oil and gas companies are permitted to develop publicly owned natural resources, they "use all reasonable precautions to prevent waste of oil or gas." 30 U.S.C. § 225.

46. Some ways oil and gas companies can waste natural gas are by intentionally venting it into the air, allowing it to leak from their equipment, or burning it in flares.

47. The Department of the Interior has long regulated venting and flaring of publicly owned natural gas produced from federal leases. *See* NTL-4A, 44 Fed. Reg. 76,600 (Dec. 27, 1979). NTL-4A required operators to get BLM approval prior to venting or flaring natural gas from oil or gas wells. It also defined when operators must pay the federal government royalties for wasted natural gas.

48. In the several decades since the Department of the Interior adopted NTL-4A, modern hydraulic fracturing techniques and directional drilling have changed how oil and gas production occurs, and new, cost-effective technologies used by oil and gas operators have been developed to minimize waste. 81 Fed. Reg. at 83,017. Prior to the Waste Prevention Rule, NTL-4A had not been revised to address these new realities.

49. In 2008, the Government Accountability Office (GAO) expressed concern about the royalty structure governing oil and gas production on Federally managed lands. GAO recognized that an evaluation of the federal oil and gas fiscal systems was overdue because the Department of the Interior had not evaluated these systems since NTL-4A was issued. GAO, *Oil and Gas Royalties: The Federal System for Collecting Oil and Gas Revenues Needs Comprehensive Reassessment*, GAO-08-691 at 8 (Sept. 2008).

50. Two years later, GAO raised concerns about BLM's inadequate regulations allowing waste of public resources. GAO recommended that BLM update its regulations to take advantage of opportunities to capture additional recoverable natural gas using available technologies. GAO, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34 at 27 (Oct. 2010).

51. BLM estimated that federal oil and gas lessees vented or flared more than 462 bcf of natural gas on public and tribal lands between 2009 and 2015. This is enough gas to supply over 6.2 million households—or every household in the States of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming—for one year. This figure does not include natural gas that leaked from various pieces of drilling, storage, and processing equipment.

52. BLM determined that the volume of waste is "unacceptably high." 81 Fed. Reg. at 83,015. In addition to wasting a valuable natural resource, states, tribes, and federal taxpayers lost

millions of dollars annually in royalty revenues. These revenues otherwise would have been available to fund schools, health care, and infrastructure.

53. Spurred by these concerns, in 2014, BLM commenced the rulemaking process for the Waste Prevention Rule. BLM solicited extensive stakeholder feedback through public forums held in communities across the country. In early 2016, BLM issued a proposed rule incorporating this feedback. BLM again held public hearings and tribal outreach sessions at locations around the country. The agency received more than 330,000 public comments. BLM finalized the Waste Prevention Rule on November 18, 2016. 81 Fed. Reg. at 83,008.

54. BLM determined that it was necessary to update NTL-4A because it did not reflect modern technologies and practices already in use by at least some operators, was subject to inconsistent application, and was not effective in minimizing waste and lost royalties, as demonstrated by the large volumes of preventable waste occurring on public and tribal lands. BLM was also concerned about the burden on BLM and operators that resulted from requiring individualized applications to vent or flare. BLM noted that its field offices were receiving a growing number of applications to vent or flare, up from just 50 in 2005 to more than 1,200 in 2014.

55. BLM replaced NTL-4A's individualized application process with nationally uniform regulations to reduce waste from venting, flaring, and leaks during oil and gas production activities.

56. BLM recognized that the required waste prevention measures would fulfill its obligations under the Mineral Leasing Act by increasing natural gas supplies, boosting royalty payments to states, tribes, and American taxpayers, reducing environmental damage, and better ensuring the safe and responsible development of oil and gas resources.

57. Specifically, the Waste Prevention Rule required operators to capture natural gas that they would otherwise vent or flare by establishing a capture target that tightens over time. The Waste Prevention Rule also set specific performance standards to reduce waste from specified types of equipment, including storage tanks and pneumatic controllers, and required operators to inspect their facilities for leaks periodically, and to repair promptly any leaks identified. Additionally, to encourage operators to address waste prevention prior to drilling, the Waste Prevention Rule required them to submit waste management plans with their applications for permits to drill.

58. The Waste Prevention Rule included exemptions if compliance with particular provisions would cause operators to abandon development of significant oil or gas resources.

59. In addition to mandating action to prevent waste, the regulations also clarified when produced gas lost through venting, flaring, or leaks is subject to royalties, and when operators may use gas royalty-free on site.

60. The Waste Prevention Rule's effective date was January 17, 2017. Starting that day, operators were required to comply with some of the Waste Prevention Rule's requirements, such as submitting waste minimization plans. But for other provisions, such as the gas capture targets and leak detection and repair requirements, BLM set January 17, 2018 as the initial compliance deadline.

61. BLM concluded that it had legal authority to issue the Waste Prevention Rule under several statutes. BLM explained that the Waste Prevention Rule met the agency's obligation under the Mineral Leasing Act to require lessees to take "all reasonable precautions" to prevent waste, 30 U.S.C. § 225, and to require operators to exercise "reasonable diligence, skill, and care" in their operations and observe "such rules . . . for the prevention of undue waste as may be prescribed by [the] Secretary," *id.* § 187. *See* 81 Fed. Reg. at 83,020.

62. BLM recognized that the Mineral Leasing Act "rests on the fundamental principle that the public should benefit from mineral production on public lands" and that an "important means of ensuring that the public benefits from mineral production on public lands is minimizing and deterring the waste of oil and gas produced from the Federal mineral estate." *Id.* at 83,019–20.

63. BLM further explained that the Rule was justified by its Mineral Leasing Act and FLPMA authorities to regulate the environmental impacts of oil and gas development from federal and tribal leases. BLM recognized that the Mineral Leasing Act "requires oil and gas leases to include provisions 'for the protection of the interests of the United States . . . and for the safeguarding of the public welfare,' which includes lease terms for the prevention of environmental harm." *Id.* at 83,020 (quoting 30 U.S.C. § 187).

64. BLM also recognized its FLPMA duty to "prevent unnecessary or undue degradation of the [public] lands." *Id.* (citing 43 U.S.C. § 1732(b)). Additionally, the agency pointed to FLPMA's express declaration that "BLM should balance the need for domestic sources of minerals

against the need to 'protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resources, and archeological values; . . . [and] provide for outdoor recreation and human occupancy and use.'" *Id.* (quoting 43 U.S.C. 1701(a)(8)).

65. BLM also concluded that the Waste Prevention Rule helps to meet its statutory trust responsibilities with respect to the development of Indian oil and gas interests.

66. In the proposed Waste Prevention Rule, BLM expressly recognized that it must consider the broader public interest when regulating waste under its statutory authorities:

> A focus on oil development rather than gas capture may be a rational decision for an individual operator, but it does not account for the broader impacts of venting and flaring, including the costs to the public of losing gas that would otherwise be available for productive use, the loss of royalties that would otherwise be paid to States, tribes, and the Federal Government on the lost gas, and the air pollution and other impacts of gas wasted through venting or flaring . . . . Thus, a decision to vent or flare that may make sense to the individual operator may constitute an avoidable loss of gas and unreasonable waste when considered from a broader perspective and across an entire field.

81 Fed. Reg. 6616, 6638 (Feb. 8, 2016).

67. BLM estimated that the Rule would reduce wasteful venting and leaking methane emissions by 35% and wasteful flaring by 49%. BLM also estimated that the Waste Prevention Rule would increase royalties by up to $14 million per year.

68. BLM found that the Waste Prevention Rule would significantly benefit local communities, public health, and the environment. For example, it would reduce flaring's visual and noise impacts.

69. BLM further found that the Waste Prevention Rule would protect communities from smog and carcinogenic air toxic emissions, and reduce greenhouse gas emissions. BLM estimated that each year the Waste Prevention Rule would reduce emissions of methane by 175,000 to 180,000 tons, VOCs by 250,000 to 2367,300 tons, and hazardous air pollutants by 1,859 to 2,031 tons.

70. BLM recognized that the Waste Prevention Rule benefited people living in Indian Country. BLM acknowledged the Rule would reduce ozone pollution and air toxic pollution as well as the noise and light pollution associated with flares in these regions.

71. BLM concluded that the Waste Prevention Rule's requirements were "economical, cost-effective, and reasonable." 81 Fed. Reg. at 83,009. BLM modeled its rules on some of the most effective State regulations adopted to address increased flaring, waste of minerals, and air pollution, such as Colorado's regulations. These state regulations have been in place for years.

72. At the same time, BLM recognized that its waste regulations had the potential to overlap with other federal, state, or tribal regulations. BLM reduced any overlap by aligning the Waste Prevention Rule with similar Environmental Protection Agency (EPA) and state rules, and including specific exemptions from the Rule where operators were already complying with EPA rules. The Waste Prevention Rule also included a provision for granting variances from particular requirements if a state or tribe could demonstrate that their regulations were equally as effective.

73. BLM found that the patchwork of EPA and other state regulations did not obviate and indeed underscored the need for uniform standards for public and Indian lands across the country. Specifically, BLM recognized that it has an independent legal obligation to prevent waste, and an interest as a land and resource manager to ensure that oil and gas development on federal leases is conducted in a manner designed to minimize its harmful impacts. BLM specifically contrasted its obligations under the Mineral Leasing Act with other statutory regimes that authorize federal agencies to delegate administration and enforcement to a state agency.

74. BLM also recognized that neither EPA nor state and tribal regulations fully address waste from BLM-managed leases. For example, over 80% of wells subject to the Waste Prevention Rule are not subject to EPA or state leak detection and repair standards. EPA regulations do not address flaring and only target new and not existing sources. Existing sources are responsible for a large percentage of the waste of publicly owned natural gas.

75. BLM also conducted a comprehensive review of state regulations and found that no state or tribe had regulations that comprehensively addressed venting, flaring, and leaks. BLM recognized that, of the states with extensive oil and gas operations on federal leases, only one has comprehensive requirements to reduce flaring, and only one has comprehensive requirements to control venting and leaks. BLM also acknowledged that state laws and regulations are subject to change, which could lead to unnecessary waste or environmental impacts.

76. BLM prepared a regulatory impact analysis (RIA) that examined the Waste Prevention Rule's costs and benefits. Overall, BLM concluded that the Waste Prevention Rule's benefits outweighed its costs "by a significant margin" with "net benefits ranging from $46 million to $199 million per year." *Id.* at 83,014. This is true even though BLM acknowledged that its cost estimates were conservative and likely overstated the Rule's impacts. Moreover, BLM did not monetize many of the Rule's benefits, such as reducing air pollution and the associated reduced health impacts.

77. BLM also evaluated the Waste Prevention Rule's costs to small businesses. It determined that the average annual compliance costs would range from about $44,600 to $65,800 for each company. Based on the midpoint average of $55,200, BLM estimated that compliance costs would constitute approximately 0.15% of per company profits. BLM therefore concluded that the Waste Prevention Rule was not expected to impact investment decisions or employment in the oil and gas industry.

78. BLM considered the impacts of the Waste Prevention Rule on low-production or "marginal" wells. The agency rejected requests to exempt marginal wells from leak detection and repair requirements.

79. BLM recognized that roughly 85% of wells on federal and tribal leases are classified as low production wells. Therefore, absent evidence showing that these wells are unlikely to leak significant volumes of gas, such an exemption would greatly reduce the Rule's waste reduction benefits. BLM pointed to peer-reviewed studies showing that both high and low production wells can have high volume leaks.

80. BLM also found that the leak detection and repair requirements were unlikely to cause a significant number of individual well shut-ins or any lease-wide shut-ins, for several reasons. First, there are third-party providers that offer leak detection services at a modest cost, and operators may recoup some of these costs through the saved gas. Second, the Rule allowed operators to request approval of an alternative leak detection program, provided they could demonstrate that it was equally effective in detecting leaks. Furthermore, the Rule allowed operators to request approval of an alternative program that was not as effective as the Rule if compliance with the Rule

would cause the operator to cease production and abandon significant recoverable oil or gas reserves.

81. BLM analyzed the benefits of the Rule using the social cost of methane. The social cost of methane measures the economic harm to society from climate change, expressed as the dollar value of the total damages from emitting one ton of methane into the atmosphere.

82. BLM relied upon an estimate of the social cost of methane published in peer-reviewed literature that includes the global economic harm of climate change. This measure was approved by an Interagency Working Group, made up of representatives of twelve agencies, including the Department of the Interior and the White House Office of Management and Budget. This estimate was based on a closely related social cost estimate for carbon dioxide developed by the Interagency Working Group in 2010. It was subject to extensive public comment and peer review, including review by the National Academy of Sciences.

83. While recognizing the limitations of the social cost of methane metric, BLM nonetheless concluded that it represented the best available information about the monetized social benefits of methane reductions to be used in a cost-benefit analysis.

II. Industry and the New Administration Made Multiple Unsuccessful Attempts to Avoid Compliance with the Waste Prevention Rule.

84. The Western Energy Alliance (WEA), Independent Petroleum Association of America, and the states of North Dakota, Wyoming, and Montana challenged the Waste Prevention Rule in the District of Wyoming. The district court denied their request for a preliminary injunction. The Waste Prevention Rule went into effect on January 17, 2017.

85. WEA, the American Petroleum Institute (API), and other industry groups also lobbied Congress to repeal the Rule using the Congressional Review Act. However, a majority of Senators voted against the motion to proceed to debate on the Congressional Review Act resolution on May 10, 2017.

86. Meanwhile, in January 2017, the Trump administration was inaugurated. On March 28, 2017, President Trump issued Executive Order No. 13,783, directing the Secretary of the Interior to consider revising or rescinding the Waste Prevention Rule. Exec. Order No. 13,783, Promoting

Energy Independence and Economic Growth, at § 7(b)(iv), 82 Fed. Reg. 16,093, 16,093 (Mar. 28, 2017).

87. The next day, Secretary Zinke issued Secretarial Order No. 3349, directing the BLM Director to review the Waste Prevention Rule and report to the Assistant Secretary of Land and Minerals Management within 21 days on whether the Waste Prevention Rule is fully consistent with the policies set forth in Executive Order No. 13,783. Secretary of the Interior, Order No. 3349, American Energy Independence, at § 5(c)(ii) (Mar. 29, 2017).

88. In response to the Secretarial Order, BLM determined that the Waste Prevention Rule is not consistent with Executive Order No. 13,783's policies. Under Secretary Zinke's leadership, BLM then took numerous, unsuccessful steps to prevent its own Waste Prevention Rule from going into full effect.

89. On June 15, 2017, without notice or an opportunity for public comment, BLM issued a notice under 5 U.S.C. § 705 staying all sections of the Waste Prevention Rule with compliance dates one year or more after the Rule's effective date. 82 Fed. Reg. 27,430 (June 15, 2017).

90. The Conservation and Tribal Citizen Groups, as well as the States of California and New Mexico, filed suit against BLM's stay in the Northern District of California.

91. On October 4, 2017, the court granted the Conservation and Tribal Citizen Groups' and the states' motions for summary judgment, holding that BLM's attempt to stay the Rule's compliance dates violated the APA. *California I*, 2017 WL 4416409, at *14. The court vacated the stay, and ordered BLM to reinstate the Rule in its entirety. *Id.*

92. One day after the *California I* court reinstated the Waste Prevention Rule, BLM proposed to suspend most of the Rule's compliance obligations for a year. 82 Fed. Reg. 46,458 (Oct. 5, 2017). BLM finalized the Suspension Rule on December 8, 2017. 82 Fed. Reg. 58,050 (Dec. 8, 2017) (Suspension Rule).

93. In the Suspension Rule, BLM indicated that in response to Executive Order 13,783 and Secretarial Order 3349, it found that "some provisions of the [Waste Prevention Rule] add considerable regulatory burdens that unnecessarily encumber energy production, constrain economic

growth, and prevent job creation." 82 Fed. Reg. at 58,050. BLM identified concerns about the Rule's impacts on marginal wells and small operators.

94. The Conservation and Tribal Citizen Groups, as well as the States of California and New Mexico, again filed suit against the Suspension Rule in the Northern District of California.

95. On February 22, 2018, the court granted the Conservation and Tribal Citizen Groups' and the states' motions for a preliminary injunction. *California II*, 286 F. Supp. 3d at 1058.

96. The *California II* court recognized that BLM's newfound concerns about the Waste Prevention Rule's burdens were inconsistent with its prior findings that the Rule was cost-effective and reasonable. *Id.* at 1065. Accordingly, the court held that "BLM must 'provide a more detailed justification than what would suffice for a new policy created on a blank slate.'" *Id.* (quoting *Fox Television*, 556 U.S. at 515). The court then reviewed each of BLM's justifications for the Suspension Rule in turn and found them lacking.

97. For example, the *California II* court held that BLM provided no factual support for its claims that the Rule would encumber energy production, constrain economic growth, and prevent job creation, or that it would be an economic burden for operators of marginal wells. *Id.* Similarly, the court found no support for BLM's claim that the Rule would disproportionately affect small operators, holding that this conclusion was entirely inconsistent with BLM's own finding that the Suspension Rule would not have a significant economic impact on small businesses. *Id.* at 1066.

98. The *California II* court also held that the additional emissions caused by suspending the Waste Prevention Rule for a year "will cause irreparable public health and environmental harm to [members of the public] who live and work on or near public and tribal lands with oil and gas development." *Id.* at 1073. The court recognized the health risks in areas that are violating federal ozone standards, explaining that increasing VOC emissions in "at risk communities" could "lead[] to and exacerbate[e] impaired lung functioning, serious cardiovascular and pulmonary problems, and cancer and neurological damage." *Id.* at 1073–74.

99. Because the *California II* court enjoined the Suspension Rule, the Waste Prevention Rule went fully into effect, and operators were required to comply with all of its provisions.

100. Faced with these compliance obligations, industry groups and the states who challenged the Waste Prevention Rule in the District of Wyoming sought various forms of relief in that court.

101. On April 4, 2018, the District of Wyoming stayed implementation of the Waste Prevention Rule until BLM finalized the Rescission Rule. Order, *Wyoming v. U.S. Dep't of the Interior*, No. 2:16-cv-00285-SWS (D. Wyo. Apr. 4, 2018), ECF No. 215. Despite having previously found that Petitioners were not entitled to a preliminary injunction, the District of Wyoming issued the stay. In issuing the stay, the District of Wyoming did not consider the four factors requisite for obtaining a preliminary injunction.

102. The Conservation and Tribal Citizen Groups and the states of California and New Mexico appealed that decision to the Tenth Circuit. On June 4, 2018, the Tenth Circuit denied motions to dismiss the appeal. In a split 2-1 decision, the court also denied the appellants' motions for a stay pending appeal. *Wyoming v. U.S. Dep't of the Interior*, Nos. 18-8027, 18-8029, 2018 WL 2727031, at *1–2 (10th Cir. June 4, 2018). Merits briefing in that appeal is ongoing.

III. BLM Rescinds the Waste Prevention Rule Based on Unsupported Assertions.

103. The same day that the *California II* Court preliminarily enjoined the Suspension Rule, Secretary Zinke's BLM proposed to rescind almost all of the requirements in the Waste Prevention Rule that would "generate benefits of gas savings or reductions in methane emissions" on the basis that the provisions "pose a compliance burden to operators." 83 Fed. Reg. 7,924, 7,938 (Feb. 22, 2018) (proposed Rescission Rule).

104. BLM only allowed 60 days for public comments on the proposed Rescission Rule. BLM did not hold any public hearings. BLM did not hold any tribal consultation hearings. BLM did not grant requests to extend the comment period.

105. BLM received over 600,000 public comments. The vast majority of these comments opposed BLM's proposal. The Conservation and Tribal Citizen Groups and thousands of their members submitted comments.

106. BLM published the final Rescission Rule on September 28, 2018. 83 Fed. Reg. at 49,184.

107. The Rescission Rule eliminates almost all of the Waste Prevention Rule's provisions responsible for its waste reduction benefits, including requirements that operators submit waste minimization plans, conduct leak detection and repair, and retrofit outdated pneumatic devices and storage vessels.

108. With respect to venting and flaring from oil wells, the Rescission Rule replaces the capture percentage requirement with a provision that allows royalty-free venting or flaring as long as it is consistent with any applicable state or tribal regulations. If no such regulations exist, the Rescission Rule imposes a system similar to NTL-4A, in which BLM must approve all applications to vent or flare gas.

109. BLM first justifies the Rescission Rule by claiming that the Waste Prevention Rule exceeded BLM's statutory authority. BLM attempts to circumscribe its own authority by pointing to its purported "longstanding" practice of interpreting "waste" as delimited by "the economics of capturing and marketing the gas" as perceived by an individual operator. In the Rescission Rule, BLM thus defines "waste of oil or gas" to include only those measures "where compliance costs are not greater than the monetary value of the resources they are expected to conserve." 43 C.F.R. § 3179.3. BLM's new definition of waste focuses exclusively on whether a private operator is making a profit, which depends on each company's individual financial and operational choices.

110. BLM fails to reconcile its new argument that the Waste Prevention Rule exceeds BLM's statutory authority with the arguments that it made in adopting the Waste Prevention Rule and defending it in court. In particular, BLM fails to reconcile its new definition of waste with its previous recognition in 2016 that, when regulating waste, it also must consider the interests of the public and state, tribal, and local governments entitled to royalty payments.

111. In the Rescission Rule, BLM claims that the Waste Prevention Rule usurped the Clean Air Act authority of the EPA, states, and tribes. But BLM provides no legal support for this claim. Nor does BLM reconcile its new legal position with the arguments that it made in adopting the Waste Prevention rule and defending it in court.

112. BLM provides no explanation for how the Rescission Rule is consistent with its statutory duties to protect the interests of the United States and the public welfare under the Mineral

Leasing Act, 30 U.S.C. § 187, or to protect air and atmospheric values under FLPMA, 43 U.S.C. §§ 1701(a)(8), 1732(b). BLM ignores these statutory obligations altogether.

113. Like the Suspension Rule, BLM justifies the Rescission Rule based on the review mandated by Executive Order 13,783 and Secretarial Order 3349. BLM found the Waste Prevention Rule "would have added . . . regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation." 83 Fed. Reg. at 49,184, 49,185. BLM provides no support for these claims, which are contradicted by its conclusion that the Rescission Rule will not affect price, supply or distribution of energy, will not alter investment and employment decisions, and will *decrease* gas production by 299 bcf.

114. BLM analyzes the Rescission Rule's economic impact on small businesses and estimates that the per-entity reduction in compliance costs results in an average increase in profit margin of only 0.19%. BLM concludes that the Rescission Rule will not have a significant effect on a substantial number of small entities.

115. In the Rescission Rule, BLM claims that the compliance costs associated with the pneumatic controller, pneumatic diaphragm pumps, and leak detection and repair requirements would especially burden marginal wells. Although in 2016 BLM recognized that marginal wells could take advantage of the Rule's exemptions, BLM now claims that the exemption process poses "excessive" burdens. BLM also claims that some marginal wells might be prematurely shut-in due to the costs and uncertainties involved in obtaining an exemption.

116. BLM relies entirely on a new, nontransparent analysis of marginal wells that was not available for public comment. In its new Regulatory Impact Analysis for the Rescission Rule (2018 RIA), BLM purports to calculate, for the first time, "the per-well reduction in revenue from the costs imposed by the requirements in the 2016 rule." BLM provides no information on the various cost assumptions for their calculations, including "lifting costs" or the "total" and "annualized" costs of the 2016 rule, nor does BLM even explain for what "select requirements" from the 2016 rule it is assessing costs.

117. BLM also fails to meaningfully explain why it discounted contrary evidence that the Waste Prevention Rule would have a limited impact on marginal wells, including but not limited to

two analyses the Conservation and Tribal Citizen Groups provided in their comments. The first, by MJ Bradley and Associates in 2018, showed that the decision as to whether or not to shut-in a well is based not on revenue, but primarily on well production numbers, which are unaffected by compliance costs. The second, by the Conservation Economics Institute in 2016, found that the Waste Prevention Rule would not impose a significant cost burden on marginal wells.

118. Nor does BLM tailor the Rescission Rule to address any specific concerns about marginal wells. Instead, it eliminates the leak detection and repair and pneumatic equipment requirements for all wells.

119. Nor does BLM tailor the Rescission Rule to its own definition of waste. For example, under BLM's new definition, the continued use of high-bleed pneumatics devices constitutes waste. BLM acknowledges that the Waste Prevention Rule's requirement to replace high-bleed pneumatic controllers with low-bleed devices would impose costs of about $12 to 13 million over 10 years and generate costs savings from product recovery of $20 to 26 million over the same timeframe. BLM nevertheless rescinds that requirement, in part because it anticipates that operators will voluntarily replace pneumatic controllers where it is profitable to do so.

120. In a 180-degree change in position from its 2016 conclusions, BLM finds that uniform federal standards are not necessary and that existing EPA and state regulations in combination with a backstop similar to NTL-4A are sufficient to prevent waste. But BLM fails to explain how a return to what was essentially the regulatory status quo prior to its adoption of the Waste Prevention Rule will not lead to the same emission levels that it previously deemed "unacceptably high." Nor does it explain how widely different state and tribal rules constitute "*all* reasonable precautions to prevent waste."

121. In the Rescission Rule, BLM claims that the Waste Prevention Rule created unnecessary regulatory overlap with EPA and state regulations. But BLM ignores the fact that EPA and state regulations do not address most oil and gas wells on federal and tribal leases. For example, Conservation and Tribal Citizen Groups provided a recent analysis showing that more than 80% of wells subject to the Waste Prevention Rule are not subject to EPA or state leak detection standards.

122. In the Rescission Rule, BLM claims that operators will eventually replace existing sources with new sources, which will be subject to EPA regulations. But BLM fails to address whether it is consistent with its Mineral Leasing Act obligations to allow waste to continue for seven years (in the case of pneumatic controllers). Nor does BLM acknowledge—much less explain—the significance of EPA's recent proposal to substantially weaken its regulations for new sources.

123. For venting and flaring of gas from oil wells, the Rescission Rule delegates BLM's authority to regulate waste to the states. BLM explains that 43 C.F.R. § 3179.201(a) "establishes State or tribal rules, regulations, and orders as the prevailing regulations for the venting and flaring of oil-well gas on BLM-administered leases." 83 Fed. Reg. at 49,202. BLM maintains no authority to enforce any such applicable state regulations on federal land. BLM also fails to address its previous conclusion in 2016 that such wholesale delegation to the states is impermissible.

124. In the Rescission Rule, BLM analyzes existing regulations in the ten top producing federal oil and gas states, and finds that they have statutory or regulatory provisions addressing venting and flaring that "are expected to constrain the waste of associated gas from oil wells." *Id.* BLM concedes that the regulations that it analyzed vary from state to state and that many are not as stringent as the Waste Prevention Rule, but still concludes that they constitute "reasonable precautions" to prevent waste. BLM reaches this conclusion without, however, assessing the efficacy of each state's regulations to reduce methane waste. BLM also fails to explain how its conclusion squares with its 2016 conclusion that the same state regulations were inadequate to prevent waste, and the Mineral Leasing Act's mandate that BLM require operators to use "*all* reasonable precautions to prevent waste."

125. Where states or tribes do not have venting or flaring regulations, the Rescission Rule reverts to a system "similar" to NTL-4A. BLM fails to address its own previous findings that NTL-4A was not effective and led to volumes of waste that BLM deemed unacceptably high. Indeed, BLM does not even mention the two GAO reports documenting massive and preventable waste of publicly-owned natural gas that triggered the Waste Prevention Rule in the first place. BLM also ignores other problems with NTL-4A that it identified in 2016, and were identified in the GAO reports. For example, the Rescission Rule does not address the burden imposed on BLM and

operators to file and process individualized flaring applications. Nor does it address the problem of inconsistent application by different field offices.

126. BLM relies on a new 2018 RIA to support the Rescission Rule. In contrast with the 2016 RIA, the 2018 RIA concludes that the Waste Prevention Rule's costs outweigh its benefits. However, the 2018 RIA underestimates the Waste Prevention Rule's benefits and overestimates its costs.

127. The primary change to the 2018 RIA is that it relies on a new "interim" estimate of the social cost of methane that diverges sharply from the Interagency Working Group-approved estimate that BLM used to evaluate the Waste Prevention Rule. This interim estimate, which was developed with none of the rigor of the Interagency Working Group-approved estimate, including peer review and public comment, cuts the Waste Prevention Rule's projected social benefits by up to 96%.

128. BLM relies upon the hastily-assembled "interim" estimate it has been using since early 2017 without explaining whether it is undergoing any process to finalize this "interim" estimate, what that process comprises, and when it expects that process to be complete.

129. The new interim social cost of methane rests on two fundamental changes. First, it purports to exclude all costs from harms that occur outside of the United States. BLM does not acknowledge that the National Academies and the Interagency Working Group have concluded that no good methodologies exist for excluding non-domestic harms. BLM also fails to acknowledge that because of the global economy's highly integrated nature, the international impacts of climate change will inevitably spill over into the United States, creating *domestic* harms. BLM has no answer to comments pointing out these domestic harms in its final rule; instead, it simply ignores this important aspect of the problem. BLM fails to explain its disregard for this evidence or its prior reliance on the social cost of methane that was not so limited.

130. Second, the 2018 RIA relies on a higher range of discount rates to calculate lost benefits from reductions of methane emissions than the central estimate discount rate BLM relied upon to calculate the same benefits in the Waste Prevention Rule. In the 2018 RIA, BLM calculated the range of benefits from reductions of methane emissions at discount rates of 7% and 3%, rather

than relying on the 3% discount rate it used for the calculating the same benefits in the Waste Prevention Rule. BLM explained in the Waste Prevention Rule rulemaking that it used a 3% discount rate because it was the estimate deemed to be "central" by the Interagency Working Group, which evaluated the social cost of methane at model averages using a 2.5%, 3%, and 5% discount rates, along with the 95th percentile of the pooled estimates from all social cost of methane models and scenarios using a 3% discount rate. BLM's change to considering a range of discount rates between 3% and 7% is contrary to expert consensus and Office of Management and Budget guidance on discounting for policies with long-term, intergenerational benefits, which are appropriately evaluated using lower discount rates. BLM does not explain why a 7% discount rate is more appropriate than lower discount rates.

131. In the 2018 RIA, BLM also ignores the Waste Prevention Rule's health and safety benefits, including air quality benefits from reducing VOCs and hazardous air pollutants, reducing noise and light pollution from flaring, and improvements to worker safety. Other agencies routinely monetize public health benefits. BLM does not explain its failure to do so.

132. BLM also overestimates the Rescission Rule's compliance cost reductions in the 2018 RIA by assuming that no operators have taken any steps to comply with the Waste Prevention Rule prior to 2019. The Waste Prevention Rule took effect in January 2017, and all of its requirements have been in effect at some point. Operators have also indicated that they are complying. Many of the Waste Prevention Rule's compliance costs are capital investments in equipment upgrades. BLM does not consider in the 2018 RIA whether companies have already made these capital investments or taken steps to implement leak detection and repair, which would lessen the Rescission Rule's compliance cost reductions.

133. BLM also makes unexplained and unsupported changes to its estimates of the Waste Prevention Rule's cost and benefits in its new 2018 RIA. The 2018 RIA's cost and benefit estimates differ from those found in the draft RIA from the proposed Rescission Rule, as well as the 2016 RIA. As a result, the public could not comment on either the basis for or appropriateness of these changes.

134. For example, without any explanation of the basis for the changes, the 2018 RIA nearly doubles the estimates of the Waste Prevention Rule's "administrative burden" to industry.

135. Similarly, in 2016 BLM estimated the Waste Prevention Rule would deliver $860 million in cost savings from the sale of captured natural gas between 2019 and 2026. But in 2018 RIA, BLM estimates costs savings over that same time period as only $654 million. BLM does not explain this change.

136. In the 2018 RIA, BLM estimates that the Rescission Rule will result in lost royalties of $28.3 million (net present value using a 7% discount rate) or $79.1 million (net present value using a 3% discount rate). In contrast, in the 2016 RIA, BLM estimated that the Waste Prevention Rule would increase royalties by $65 million (using a 7% discount rate) or $82 million (using a 3% discount rate). The 2018 RIA fails to fully explain these differences.

IV. BLM's Cursory NEPA Analysis Overlooks the Rescission Rule's Significant Climate and Air Quality Impacts.

137. BLM supports the Rescission Rule with, excluding appendices, a 26-page EA. BLM concludes that the Rescission Rule has no "significant" impacts in a FONSI. It therefore did not prepare an EIS.

138. BLM did not make any substantive changes to the EA in response to public comments.

139. The EA acknowledges that the Rescission Rule will cause additional emissions of 175,000 to 180,000 tons per year of methane, 79,000 to 80,000 tons per year of VOCs, and 1,860 to 2,030 tons per year of hazardous air pollutants over the ten-year evaluation period. Although the EA quantifies these increased emissions, BLM does not analyze how those increased emissions would impact human health and the environment.

140. The EA's entire consideration of the Rescission Rule's public health impacts from increased air pollution is contained in one sentence. "These air pollutants affect the health and welfare of humans, as well as the health of plant and wildlife species."

141. The EA's discussion of the Rescission Rule's noise and light impacts from increased flaring also consists of one sentence. "We would expect additional flaring under the [Rescission

Rule], thereby increasing noise and light pollution and potentially affecting the communities living near oil and gas development, wildlife, night-sky resources, and recreationists."

142. The EA does not discuss the Rule's impacts on low-income and minority populations living near oil and gas operations, including tribal communities. Yet, it concludes that these impacts will not be significant.

143. BLM fails to consider the Rescission Rule's impacts in regions that are already suffering from air quality problems, such as ozone pollution. Ground-level ozone is a dangerous air pollutant that causes or contributes to asthma, cardiovascular disease, and even premature mortality. VOCs and nitrogen oxides emitted by oil and gas development contribute to ozone formation.

144. BLM manages leases in numerous areas of the country that are already suffering from elevated ozone levels, and in some cases areas are already violating public health standards. For example, the Uinta Basin in Utah has a substantial number of BLM-managed leases. EPA has designated this area as out of compliance with federal ozone standards. BLM does not examine the public health impact of the Rescission Rule in areas suffering from ozone pollution.

145. Conservation and Tribal Citizen Groups submitted data indicating that there are currently more than 6,000 BLM-managed wells in areas that are not meeting federal standards for ozone, and which are not subject to EPA or state leak detection requirements. BLM did not evaluate this data in the EA.

146. BLM also fails to consider the Rescission Rule's impacts on people living near BLM-managed leases, especially in tribal communities. For example, residents of the Fort Berthold Reservation in North Dakota and the Navajo Nation and other tribes in northwestern New Mexico often live in close proximity to oil and gas development. Many tribal communities adversely affected by oil and gas development already suffer disproportionately high levels of negative health effects.

147. The Waste Prevention Rule also would have controlled emissions of hazardous air pollutants, including carcinogens like benzene, that pose significant health threats to these communities. These communities also must grapple with noise and light pollution from flaring.

148. The Rescission Rule's impacts on tribal lands will be significant. Tribal lands are subject only to BLM and tribal standards. No tribe has air quality regulations as strong as the Waste Prevention Rule.

149. The EA does not consider the Rescission Rule's impacts in combination with any other past, present, or reasonably foreseeable actions. For example, the EA fails to consider the cumulative public health impacts of the Rescission Rule and other Trump administration efforts to rescind important public health protections, particularly EPA's planned revision of its oil and gas air quality rules. Although BLM acknowledges that EPA has proposed to weaken its new source performance standards for oil and gas sources, the EA's environmental analysis assumes those standards will remain in place.

150. The EA also fails to consider the Rescission Rule's impacts on climate change. For example, the EA fails to consider the localized impact of increased methane emissions in the San Juan Basin, which is a methane "hot spot." Studies have indicated that oil, gas, and coalbed methane emissions in the region are a leading cause of the hot spot.

151. The EA acknowledges the Rescission Rule will increase methane emissions by 175,000 tons in the first year. BLM states that this is 0.61% of total U.S. methane emissions in 2015. However, BLM provides no other context for the foregone emission reductions. In fact, they have the climate impact of nearly 3 million passenger vehicles driving for a year or nearly 1.5 million homes' energy use for one year.

152. BLM further fails to disclose the carbon dioxide equivalent of the foregone emission reductions using the global warming potential of methane over both a 20-year and 100-year timeframe. Global warming potential values allow BLM to estimate how many tons of carbon dioxide would be needed to produce the same amount of global warming as one ton of methane. Based on the Intergovernmental Panel on Climate Change's Fifth Assessment Report, published in 2014, methane has a global warming potential of 36 over a 100-year period and 87 over a 20-year period.

153. In order to determine that foregone emissions are 0.61% of total U.S. methane emissions, BLM had to calculate the carbon dioxide equivalent of foregone emission reductions. In

doing so, however, BLM used an outdated value from the Intergovernmental Panel on Climate Change's Fourth Assessment Report, published in 2007, and failed to analyze or provide final carbon dioxide equivalent values to inform the public and decisionmakers using both 20-year and 100-year global warming potentials provided by the 2014 Fifth Assessment Report.

154. BLM also fails to assess the cumulative impacts of the Rescission Rule's methane emissions in combination with the direct and indirect emissions of the federal and Indian oil and gas program as a whole. There are more than 100,000 federal onshore oil and gas wells, which account for about 11% of the United States' natural gas supply and about 5% of its oil supply. In Fiscal Year 2015, federal oil and gas wells produced 183.4 million barrels of oil, 2.2 trillion cubic feet of natural gas, and 3.3 billion gallons of natural gas liquids. Between 2003 and 2014, approximately 25% of all U.S. and 3–4% of global fossil fuel greenhouse gas emissions were attributable to federal coal, oil, and gas resources leased and developed by the Department of the Interior.

155. BLM does not quantify the cumulative greenhouse gas emissions caused by the Rescission Rule's increase in methane emissions when combined with the direct emissions caused by oil and gas production on federal and Indian leases as well as indirect, downstream emissions caused by the transportation, processing, and use of oil and natural gas produced from those federal and Indian leases. Nor did BLM evaluate the cumulative impact of those emissions to climate change, despite the availability of tools, such as but not limited to the social cost of carbon and methane, the global warming potential of methane over both 20-year and 100-year time frames, and carbon budgets, to do so.

156. BLM also fails to evaluate the impacts of climate change to public and tribal lands. The EA states that BLM "would anticipate additional [greenhouse gas] emissions, which would have climate impacts and air quality impacts." But the EA contends that the Rescission Rule's "impacts on climate change cannot be reliably assessed and are sufficiently uncertain as to be not reasonably foreseeable." The EA's contention is conclusory and, further, ignores the wealth of available scientific data regarding both the current and reasonably foreseeable future impacts of climate change on Western landscapes, including extreme weather, forest fires, and drought as well as adverse impacts on air quality, public health, public lands, and biodiversity.

157. The EA also fails to consider other available metrics for assessing the impacts of the Rescission Rule with respect to climate change. Despite previously relying on a global value for the social cost of methane, BLM now impermissibly attempts to limit the scope of its analysis to the effects occurring only in the United States, ignoring both global impacts as well as the international impacts of climate change that spill over into the United States, creating *domestic* harms. BLM also arbitrarily discounts the present value of climate impacts by relying on a higher range of discount rates than it did when evaluating the Waste Prevention Rule.

158. Despite BLM's failure to take a hard look at the Rescission Rule's air pollution and climate change impacts, the FONSI concludes that they are not significant.

159. The FONSI admits there will be increased emissions of air pollutants and greenhouse gases, but it concludes the impacts on public health and safety are not significant because the emissions would be geographically dispersed and would occur in sparsely populated areas. As record evidence demonstrates, however, even minor increases of pollution geographically dispersed across sparsely populated areas can cause significant climate, air quality, and public health impacts. BLM ignores the significant health impacts to a large number of people living in areas impacted by oil and gas development on federal and tribal leases.

160. The FONSI also concludes that the Rescission Rule's impacts are not significant because they do not threaten a violation of Federal, State, or local law or requirements imposed for the protection of the environment. Despite its concession that the Rescission Rule will result in foregone air quality benefits, the FONSI claims that the Rescission Rule cannot threaten requirements imposed for the protection of the environment because the purpose of the Waste Prevention Rule was to prevent waste and not to protect the environment. The FONSI ignores that the Rescission Rule will contribute to ozone pollution in areas that are already violating EPA's National Ambient Air Quality Standards for ozone.

161. The FONSI ignores the significant impacts of climate change on public health and the environment, particularly federal public lands and tribal lands, claiming those impacts "cannot be reliably assessed and thus are sufficiently uncertain as to be not reasonably foreseeable."

162. The FONSI claims that the Rescission Rule "is not related to any other BLM actions with individually insignificant but cumulatively significant impacts." The FONSI ignores the cumulative climate impacts of the Rescission Rule in combination with BLM's oil and gas leasing program. The FONSI also ignores other actions taken by federal agencies that will also increase air pollution and greenhouse gas emissions from oil and gas development, including EPA's plans to weaken its new source performance standards.

163. Despite the overwhelming public comments in support of retaining the Waste Prevention Rule, which included extensive comments on BLM's failure to adequately consider the environmental impacts, the FONSI concludes that "BLM's analysis of the environmental effects of the reversal of the 2016 rule should not be in contention." The FONSI also fails to recognize the considerable dispute about BLM's characterization of the impacts of the Rescission Rule using the new "interim" social cost of carbon rather than the Interagency Working Group-approved estimate that BLM used to evaluate the Waste Prevention Rule, which was subject to peer review and public comment.

164. In the EA, BLM defines the purpose and need for the Rescission Rule based on its unsupported finding that the Waste Prevention Rule would unnecessarily encumber energy production, constrain economic growth, and prevent job creation. The EA defines the purpose and need as "eliminat[ing] unnecessary regulatory requirements in order to more efficiently manage oil and gas operations on Federal and Indian lands."

165. BLM considers three alternatives in detail within the EA: (1) continued implementation of the Waste Prevention Rule (the no action alternative), (2) the Rescission Rule, and (3) retaining the gas capture requirements.

166. BLM identifies three additional middle-ground alternatives, but eliminates them from further discussion without any analysis. These alternatives included: (1) streamlining the waste minimization plan requirement, (2) retaining but adjusting the capture percentage framework for reducing flaring, and (3) retaining the leak detection, pneumatic controller, storage tank and other operational and equipment requirements, but applying them only to specific categories of wells—

wells that sell gas to market, wells that would receive positive returns from compliance, and wells that are not marginal.

167. Each of these alternatives would have addressed, to some degree, concerns that BLM identified in the proposed Rescission Rule. But BLM rejected these alternatives from further analysis without sufficient analysis or support. For example, BLM fails to explain how applying the rule only to wells that would receive positive returns from compliance would not eliminate what the agency deems "unnecessary regulatory burdens."

168. BLM also rejected additional reasonable alternatives recommended by the public, such as controls on the timing and location of development, designed to facilitate the reduction of methane waste.

FIRST CLAIM FOR RELIEF
(*Failure to Take All Reasonable Precautions to Prevent Waste and Protect Public Welfare and the Environment: Violation of the Mineral Leasing Act, FLPMA, and APA*)

169. The allegations in paragraphs 1–168 are incorporated herein by reference.

170. Under the Mineral Leasing Act, BLM has a duty to ensure that companies developing publicly owned oil and gas "use all reasonable precautions to prevent waste of oil or gas." 30 U.S.C. § 225. Likewise, the Mineral Leasing Act requires that each federal lease "shall contain provisions for the purpose of insuring the exercise of reasonable diligence, skill, and care in the operation of said property . . . and for the prevention of undue waste." *Id.* § 187.

171. In undertaking its duties under the Mineral Leasing Act, BLM must also provide for the "protection of the interests of the United States . . . and for the safeguarding of the public welfare." *Id.* BLM is empowered to "prescribe necessary rules and regulations" and "do any and all things necessary" to carry out these purposes. *Id.* § 189.

172. BLM adopted the 2016 Waste Prevention Rule to fulfill these legal mandates. Based on an extensive record, BLM required reasonable protective measures that are similar to measures some oil and gas operators have used for years and that some states have required through regulations.

173. The 2018 Rescission Rule eliminates many of these reasonable protections. To the extent BLM provides any explanation for why these measures are no longer reasonable, it does so by redefining waste to include only vented, flared, or leaked natural gas that is profitable for industry to capture. The Rescission Rule adds a new definition of "waste of oil or gas" to include only those measures "where compliance costs are not greater than the monetary value of the resources they are expected to conserve." 43 C.F.R. § 3179.3. This definition of waste reads the duty to prevent waste out of the Mineral Leasing Act and focuses exclusively on private interests to the exclusion of "the interests of the United States" and the "public welfare."

174. Furthermore, BLM failed to explain how the Rescission Rule's new definition of waste is permissible under its governing statutes. *Fox Television*, 556 U.S. at 514–16; 5 U.S.C. § 706(2)(A). BLM fails to explain how the Rescission Rule's new definition of waste comports with its statutory duties to protect the interests of the United States and the public welfare under the Mineral Leasing Act, 30 U.S.C. § 187, and to manage the public lands "in a manner that will protect the quality of the . . . scenic . . . environmental, [and] air and atmospheric . . . values" and "prevent unnecessary or undue degradation" under FLPMA, 43 U.S.C. §§ 1701(a)(8), 1732(b). Indeed, BLM ignores its obligations to protect the public welfare and the environment altogether.

175. BLM's exclusive focus on private interests in the Rescission Rule's definition of waste also represents an unexplained and unsupported change in position from BLM's position as contained in the Waste Prevention Rule in violation of the APA. *Fox Television*, 556 U.S. at 514–16; 5 U.S.C. § 706(2)(A).

176. Alternatively, even if BLM's new definition of waste were permissible, the Rescission Rule violates the Mineral Leasing Act because it allows waste to continue even under its own new definition. 30 U.S.C. §§ 187, 225; 5 U.S.C. § 706(2)(A).

177. Specifically, BLM concedes that the Waste Prevention Rule's requirement to use low-bleed continuous pneumatic controllers "would have imposed costs of about $12 million to $13 million and would have generated cost savings from product recovery of $20 million to $26 million," and thus was "expected to generate revenue for operators." 83 Fed. Reg. at 49,195. Nonetheless, the Rescission Rule rescinds the requirement because BLM anticipates that operators

will voluntarily use low-bleed pneumatic controllers. BLM's treatment of pneumatic controllers demonstrates that its new definition of "waste of oil and gas" is only a pretense, and BLM's true aim is not to impose *any* reasonable precautions to prevent waste (much less "all"), as it will decline to regulate regardless of whether the requirement meets its new definition.

178. The Rescission Rule's new definition of waste, as well as the Rule's allowance for continued waste that conflicts with even that definition, is contrary to the Mineral Leasing Act's plain language and purpose, 30 U.S.C. §§ 187, 225, and is not in accordance with law in violation of the APA, 5 U.S.C. §§ 706(2)(A), (C), (D).

SECOND CLAIM FOR RELIEF

(Illegal Reliance on State Standards: Violation of the Mineral Leasing Act, FLPMA, and APA)

179. The allegations of paragraphs 1–168 are incorporated herein by reference.

180. The Mineral Leasing Act directs the Secretary of the Interior to oversee the leasing and development of publicly owned minerals, including the mandate to ensure operators "use all reasonable precautions to prevent waste of oil or gas." 30 U.S.C. § 225; *see also id.* §§ 181, 187, 189. FLPMA further grants the Secretary exclusive control over the management and protection of public lands. *See* 43 U.S.C. §§ 1701(a)(1), (5), 1702(e), 1731(b), 1732(a), (b), 1740. Neither the Mineral Leasing Act nor FLPMA authorize the Secretary to delegate his authority to state governments, nor is there any evidence that Congress intended to allow such delegation.

181. In the Rescission Rule, BLM abdicates its statutory responsibility, providing that oil wells may vent or flare gas royalty free "if it is vented or flared pursuant to applicable rules, regulations, or orders of the appropriate State regulatory agency or tribe." 43 C.F.R. § 3179.201. BLM states that this provision "establishes State or tribal rules, regulations, and orders as the prevailing regulations for the venting and flaring of oil-well gas on BLM administered leases." 83 Fed. Reg. at 49,202. BLM maintains no authority to enforce any such applicable state or tribal regulations on federal land. Nor is there anything in the regulation to prevent or address the prospect of states from altering or weakening their standards inconsistent with the Mineral Leasing Act or FLPMA.

182. Under § 3179.201, any state regulation or order that applies to venting or flaring is

deemed sufficient to meet BLM's legal obligations under the Mineral Leasing Act and FLPMA. However, BLM has not analyzed whether the relevant state standards conform to BLM's federal statutory obligations, including but not limited to the obligations to ensure operators "use all reasonable precautions to prevent waste of oil or gas," 30 U.S.C. § 225, and to "prevent unnecessary or undue degradation of the [public] lands," 43 U.S.C. § 1732(b). Instead, BLM only prepared a cursory 6-page memorandum that provides a short summary of each state's rules and standards, but does not analyze the effectiveness of these standards.

183. BLM recognizes that it has an independent obligation to ensure that operators use all reasonable precautions to prevent waste when it concedes that if a state "were to propose a relaxation of [its] restrictions on flaring, and the BLM judged that it allowed for undue waste of Federal gas, then the BLM would move swiftly to amend § 3179.201 to preclude deference to that State's flaring regulations." 83 Fed. Reg. at 49,203. But BLM does not explain how each of the widely varying current state and tribal standards constitutes "*all* reasonable precautions to prevent waste." Nor does it explain how its conclusion that the current state and tribal standards represent "all reasonable precautions" can be true in light of the GAO reports' and its own prior finding of enormous quantities of preventable gas waste.

184. BLM also fails to explain its change in position from recognizing that it had an independent legal responsibility to ensure compliance with uniform federal standards to deferring completely to varying state standards.

185. BLM also fails to explain and support its change in position with respect to its earlier finding, supported by a factual analysis, that existing state regulations are inadequate to fulfill BLM's independent mandate.

186. BLM's decision to delegate its statutory obligations to states violates the Mineral Leasing Act and FLPMA, and is arbitrary and capricious and in excess of statutory authority in violation of the APA. 5 U.S.C. §§ 706(2)(A), (C), (D). BLM's reliance on state and tribal regulations also represents an unexplained and unsupported change in position in violation of the APA. *Id.* §§ 706(2)(A), (D); *Fox Television*, 556 U.S. at 515–16.

THIRD CLAIM FOR RELIEF
(Arbitrary Revision of the Waste Prevention Rule: Violation of the APA)

187. The allegations in paragraphs 1–168 are incorporated here by reference.

188. Under the APA, when a federal agency implements substantive revisions to a final, effective regulation, it must show there are "good reasons" for changing the rule and offer a "reasoned explanation" for its changed position. *Fox Television*, 556 U.S. at 514–16. Where a "new policy rests upon factual findings that contradict those which underlay its prior policy," a "more detailed justification" is required. *Id.* at 515

189. BLM's reasons for rescinding or modifying the provisions of the Waste Prevention Rule fail to meet the APA standards. For example, BLM fails to offer a reasoned explanation for changing its finding that the Waste Prevention Rule's requirements were "economical, cost-effective, and reasonable." 81 Fed. Reg. at 83,009. Indeed, BLM's claim that the Waste Prevention Rule's provisions "add[] regulatory burdens that unnecessarily encumber energy production, constrain economic growth and prevent job creation," 83 Fed. Reg. at 49,184, contradicts BLM's prior conclusions, its own analysis in the Rescission Rule, and other evidence before the agency.

190. BLM further fails to offer any good reasons or a reasoned explanation for changing its findings with respect to the impact of the Waste Prevention Rule on marginal wells. BLM offers no support for its claim that the Waste Prevention Rule's requirements will impose a burden on marginal wells beyond a novel and nontransparent comparison of marginal well revenue to compliance costs, that was not available for public comment (addressed in the Fourth Claim for Relief). Likewise, BLM offers no evidence that the costs and uncertainties involved in obtaining an exemption would cause operators to shut in wells prematurely. *Id.* at 49,187, 49,206. Indeed, BLM ignored evidence submitted by Conservation and Tribal Citizen Groups to the contrary. BLM also arbitrarily failed to tailor the Rescission Rule to address this concern.

191. BLM fails to provide a reasoned explanation for reversing its finding that EPA air quality regulations and state regulations (addressed in Second Claim for Relief) do not obviate the need for BLM waste regulations. BLM fails to explain how its reliance on EPA regulations is permissible to meet its independent statutory obligations to prevent waste, particularly because EPA

has announced plans to revise or even rescind its regulations, important factors that BLM ignores. BLM also fails to explain its change in position from previously concluding that BLM regulations are necessary because EPA regulations do not address existing source emissions, and fails to explain how allowing waste to continue from existing sources is permissible under the Mineral Leasing Act.

192. BLM fails to provide a reasoned explanation for reversing its finding that the NTL-4A framework is not effective and led to impermissible waste, and that it was necessary to replace NTL-4A to reduce burdens on BLM and operators, and inconsistent application by various field offices. BLM fails to acknowledge the factual findings underpinning the Waste Prevention Rule including the conclusions of the GAO reports, much less provide a detailed explanation for why these factual findings were erroneous or it should change policy notwithstanding these findings.

193. In adopting the Rescission Rule, BLM also omits consideration of relevant factors and data, relies on factors which Congress did not intend the agency to consider, and offers rationales that are unsupported or run counter to the evidence in the administrative record, lack a rational basis, represent unexplained and unsupported changes in position, and are otherwise arbitrary and capricious in violation of the APA. 5 U.S.C. § 706(2)(A).

FOURTH CLAIM FOR RELIEF

(Arbitrary Assessment of Costs and Benefits: Violation of the APA and Failure to Provide for Meaningful Public Comment)

194. The allegations in paragraphs 1–168 are incorporated here by reference.

195. BLM relies on its reassessment of the costs and benefits of the Waste Prevention Rule to justify the Rescission Rule, but it arbitrarily underestimates the benefits and overstates the costs of the Waste Prevention Rule.

196. BLM dramatically reduces the benefits of the Waste Prevention Rule by relying on an “interim” social cost of methane that fails to consider significant domestic and global impacts. BLM fails to offer good reasons for relying on this new “interim” estimate, which relies on methodologies that are unsupported in the record and contrary to expert consensus. BLM also fails to explain and support the “interim” changes to the social cost of methane estimate, including its choice to present a

discounted range of estimates of climate impacts that undervalue the future effects of climate change.

197. While BLM focuses on costs of the Waste Prevention Rule, it arbitrarily fails to monetize or adequately consider the public health and worker safety benefits of the Waste Prevention Rule (or, correspondingly, costs of the Rescission Rule).

198. BLM arbitrarily overstates the compliance cost reductions associated with the Rescission Rule by assuming, with no support, that operators have taken no steps to comply with the Waste Prevention Rule.

199. BLM also fails to adequately explain changes to the estimates of cost savings and administrative burdens provided by the Waste Prevention Rule.

200. BLM argues that the Rescission Rule is necessary based on concerns that the requirements of the Waste Prevention Rule would cause operators to prematurely shut-in marginal wells. In the Rescission Rule, BLM relies on a new and nontransparent “additional quantitative analysis” of revenue at marginal wells to support these concerns. This novel analysis was not presented for public comment on the Rescission proposal, and contradicts analysis presented by Conservation and Tribal Citizen Groups, and disregarded by BLM, that shut-ins at marginal wells are not associated with well revenue, but rather well production.

201. BLM’s assessment of the costs and benefits of the Waste Prevention Rule and Rescission Rule omits consideration of relevant factors and data, relies on factors which Congress did not intend the agency to consider, and offers rationales that are unsupported or run counter to the evidence in the administrative record, lack a rational basis, represent unexplained and unsupported changes in position, and are otherwise arbitrary and capricious in violation of the APA. 5 U.S.C. §§ 706(2)(A), (C), (D); *Fox Television*, 556 U.S. at 514–16.

202. BLM’s failure to explain changes in its assessment methodology for its cost benefit analysis and its inclusion of a novel “analysis” of marginal well revenue also rendered the opportunity for public comment meaningless. *See* 5 U.S.C. § 553.

FIFTH CLAIM FOR RELIEF
(Failure to Take a "Hard Look" at Environmental Impacts and Environmental Justice Concerns: Violation of NEPA)

203. The allegations in paragraphs 1–168 are incorporated herein by reference.

204. NEPA is our "basic national charter for protection of the environment." 40 C.F.R. § 1500.1(a). The Act makes environmental protection a part of the mandate of every federal agency.

205. NEPA is intended "to foster excellent action" and "to help public officials make decisions that are based on [an] understanding of environmental consequences, and take actions that protect, restore, and enhance the environment." *Id.* § 1500.1(c).

206. To that end, NEPA requires federal agencies to take a "hard look" at the environmental impacts of proposed actions before the agency makes an irreversible and irretrievable commitment of resources. 42 U.S.C. § 4332; 40 C.F.R. §§ 1500.1, 1508.9. NEPA requires agencies to use high quality, accurate scientific information and to ensure the scientific integrity of the analysis. 40 C.F.R. §§ 1500.1(b), 1502.24.

207. Agencies must consider the direct, indirect, and cumulative impacts of their actions. *Id.* §§ 1502.15, 1508.7, 1508.8, 1508.25(c). Direct impacts are those impacts "caused by the action and [that] occur at the same time and place." *Id.* § 1508.8. Indirect impacts are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." *Id.* Cumulative impacts are "the impact[s] on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." *Id.* § 1508.7.

208. When an agency has "incomplete or unavailable information" about the reasonably foreseeable impacts of a project, the agency must determine whether it can reasonably obtain the missing information. *Id.* § 1502.22. If not, the agency must acknowledge that information is incomplete or unavailable, discuss its relevance for evaluating the impacts of the action, summarize existing credible information, and apply any "theoretical approaches or research methods generally accepted in the scientific community." *Id.* § 1502.22(b). The agency must analyze "impacts which

have catastrophic consequences, even if their probability of occurrence is low, provided that the analysis of the impacts is supported by credible scientific evidence, is not based on pure conjecture, and is within the rule of reason." *Id.*

209. NEPA requires federal agencies to prepare an EIS for all "major Federal actions significantly affecting the environment." 42 U.S.C. § 4332(2)(C); 40 C.F.R. § 1501.4. To assess whether impacts are significant, an agency may prepare an EA. If an agency determines through the preparation of an EA that no EIS is required, it must document that finding in a FONSI that supplies a convincing statement of reasons explaining why a proposed action's impacts are insignificant. 40 C.F.R. § 1508.9. An EIS must be prepared if there are substantial questions that the proposed action may cause significant degradation of the environment.

210. To determine whether an action has significant environmental impacts, an agency must consider both the context and intensity. An agency must evaluate the impact of an action in all relevant contexts, including global, national, and local. *Id.* § 1508.27(a); *see also* 42 U.S.C. § 4332(2)(F) (directing agencies to "recognize the worldwide and long-range character of environmental problems"). In evaluating intensity, the agency must consider the following, among other factors:

- "[t]he degree to which the proposed action affects public health or safety,"
- "[t]he degree to which the effects on the quality of the human environment are likely to be highly controversial,"
- "possible effects on the human environment are highly uncertain or involve unique or unknown risks,"
- "whether the action is related to other actions with individually insignificant but cumulative significant impacts," and
- "[w]hether the action threatens a violation of Federal, State, or local law or requirements imposed for the protection of the environment."

40 C.F.R. § 1508.27.

211. In addition to NEPA's requirements, Executive Order 12,898 (Feb. 16, 1994) requires federal agencies to incorporate environmental justice as part of their missions. The Council on Environmental Quality (CEQ), the agency charged with implementing NEPA, has issued guidance for agencies on implementing Executive Order 12,898 in NEPA analyses. *See* CEQ, Environmental Justice Guidance Under the National Environmental Policy Act (Dec. 10, 1997). The guidance

instructs agencies to consider whether there may be disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, or Indian Tribes.

212. BLM failed to take a hard look at the Rescission Rule's direct, indirect, and cumulative impacts on climate, public health, and local communities, including disproportionately affected tribal communities.

213. The EA ignores the impacts of increasing VOC emissions in areas already suffering from unhealthy ozone pollution or the impacts of increased pollution on local communities. The EA also fails to consider the environmental justice implications of increasing pollution in tribal communities. The EA further fails to consider these public health impacts in combination with other past, present, or reasonably foreseeable actions, including EPA's planned revisions of its oil and gas air quality regulations.

214. BLM failed to take a hard look at the Rescission Rule's direct, indirect, and cumulative climate impacts from increased methane emissions. The EA fails to consider the Rescission Rule's impacts to specific geographies with existing, high-levels of methane pollution, in particular the San Juan Basin, which underlies a methane "hot spot." The EA also fails to take a hard look at the different short term and long-term warming impacts of methane. BLM fails to evaluate or disclose to the public the carbon dioxide equivalent of the increase in methane emissions under the Rescission Rule using the current, and best available, global warming potential values for methane of 36 (100-year) and 87 (20-year). Additionally, the EA, despite purporting to assess the effects of a nationwide rule, fails to take a hard look at the cumulative effects to the climate of increased methane emissions in combination with the BLM's nationwide federal public lands oil and gas program, including by failing to evaluate the magnitude or severity of the increased emissions and the emissions caused in total by BLM's nationwide federal public lands oil and gas program using existing tools such as the social cost of methane or carbon budgeting.

215. BLM also violated NEPA by impermissibly claiming, in a conclusory fashion, that BLM cannot consider the effects of climate change on public and tribal lands affected by the Rescission Rule. BLM did so despite the wealth of available qualitative and quantitative scientific data, information, and assessments regarding both current and reasonably foreseeable future impacts

in the western United States. Moreover, even if some information is unavailable, BLM failed to identify the relevance of the information, provide a summary of existing credible scientific evidence, or evaluate climate change impacts based upon generally accepted theoretical approaches or research methods. *See* 40 C.F.R. § 1502.22(b).

216. BLM also failed to take a hard look at the social cost of the Rescission Rule, despite the availability of a metric that allows it to do so: the Interagency Working Group's social cost of methane. BLM's reliance on the "interim" social cost of methane fails to consider significant domestic and global harms, arbitrarily undervalues the future effects of climate change, lacks professional and scientific integrity, ignores information from expert agencies, and underscores the significance, in particular the highly controversial nature, of its proposed action. By failing to consider the Interagency Working Group's social cost of methane, BLM improperly skewed its decision-making process, considering the Rescission Rule's monetized benefits in a vacuum, while discounting, if not entirely ignoring, the Rescission Rule's costs to the global and domestic environment.

217. BLM's failure to take a hard look at the Rescission Rule's environmental impacts fatally undermines the agency's conclusion, in the FONSI, that they will not be significant. The FONSI fails to provide a convincing statement of reasons justifying its decision to forego preparation of an EIS, which would have acknowledged the significance of the Rescission Rule's impacts to the environment while affording the agency the opportunity to prepare a comprehensive environmental review to ensure a reasoned and informed rulemaking. Under NEPA, BLM must prepare an EIS due to the Rescission Rule's significance in the global and national context and the extensive record evidence showing negative public health impacts, high degree of controversy, uncertainty surrounding the use of the social cost of methane, cumulative climate and public health impacts, and potential contribution to violations of federal ozone standards.

218. For these reasons, BLM's Rescission Rule and underlying EA and FONSI violate NEPA and are arbitrary, capricious, an abuse of discretion, otherwise not in accordance with law, and without observance of procedure required by law. 5 U.S.C. §§ 706(2)(A), (C), (D).

SIXTH CLAIM FOR RELIEF
(Failure to Define a Valid Purpose and Need and Consider a Reasonable Range of Alternatives: Violation of NEPA)

219. The allegations in paragraphs 1–168 are incorporated herein by reference.

220. NEPA requires that an EIS or EA articulate a valid purpose and need for the proposed action under review. 40 C.F.R. §§ 1508.9(b), 1502.13.

221. Consistent with the purpose and need, the agency must discuss "alternatives to the proposed action." 42 U.S.C. § 4332(2)(C) (EIS); *id.* § 4332(2)(E) (EA). The range of alternatives is the "heart" of the NEPA analysis, "sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public." 40 C.F.R. §§ 1502.14, 1508.9(b).

222. Agencies must "[r]igorously explore and objectively evaluate all reasonable alternatives," and adequately explain and support its decision to eliminate consideration of particular alternatives. *Id.* § 1502.14(a).

223. In the Rescission Rule, BLM improperly subordinates its statutory duty to prevent waste beneath an unsupported desire to reduce agency and industry compliance burdens and costs. Indeed, BLM's own analysis shows that there is no need "to eliminate unnecessary regulatory requirements in order to more efficiently manage oil and gas operations on Federal and Indian Lands."

224. Due to BLM's impermissibly narrow purpose and need, the agency failed to consider a range of reasonable alternatives. In particular, BLM specifically failed to seriously consider reasonable alternatives, such as maintaining the Waste Prevention Rule (the no action alternative), action to strengthen the Waste Prevention Rule to provide even greater protections against waste of publicly owned natural resources whether identified independently or as recommended by the public, or to consider in detail certain reasonable (if modest) middle-ground alternatives BLM itself identified. BLM failed to adequately explain or support its rejection of these reasonable and middle-ground alternatives.

225. For these reasons, BLM's Rescission Rule and underlying EA and FONSI violate NEPA and are arbitrary, capricious, an abuse of discretion, otherwise not in accordance with law, and without observance of procedure required by law. 5 U.S.C. §§ 706(2)(A), (C), (D).

PRAYER FOR RELIEF

Plaintiffs respectfully request that this Court:

1. Issue a declaratory judgment that BLM violated the APA, Mineral Leasing Act, FLPMA, NEPA, and acted arbitrarily, capriciously, contrary to law, and in excess of statutory authority by issuing the Rescission Rule;

2. Vacate the Rescission Rule and reinstate the Waste Prevention Rule in its entirety;

3. Award the Conservation and Tribal Citizen Groups their costs, expenses, and reasonable attorney fees; and

4. Provide such other relief as the Court deems just and proper.

Respectfully submitted this 28th day of September, 2018,

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